ORAL ARGUMENT NOT YET SCHEDULED

No. 23-1173

IN THE

United States Court of Appeals for the District of Columbia Circuit

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA,

Petitioner,

v.

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION AND UNITED STATES DEPARTMENT OF TRANSPORTATION,

Respondents,

On Petition for Review of a Final Rule from the United States Department of Transportation and Pipeline and Hazardous Materials Safety Administration

JOINT APPENDIX

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March 25, 2024

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Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	
Willow Creek	At the Black Fork Creek confluence	+419	+423	City of Tyler, Unincorporated Areas of Smith County.
	Approximately 375 feet upstream of West Front Street	None	+522	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.
** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.
Send comments to Luis Rodriguez, Chief, Engineering Management Branch, Federal Insurance and Mitigation Administration, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Tyler
Maps are available for inspection at the Development Services Office, 423 West Ferguson Street, Tyler, TX 75702.

Unincorporated Areas of Smith County
Maps are available for inspection at the Smith County Courthouse, 100 North Broadway Avenue, Tyler, TX 75702.

(Catalog of Federal Domestic Assistance No. 97.022, ''Flood Insurance.'')

Dated: August 12, 2011.

Sandra K. Knight,

Deputy Federal Insurance and Mitigation Administrator, Mitigation, Department of Homeland Security, Federal Emergency Management Agency.

[FR Doc. 2011–21709 Filed 8–24–11; 8:45 am]

BILLING CODE 9110–12–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket No. PHMSA–2011–0023]

RIN 2137–AE72

Pipeline Safety: Safety of Gas Transmission Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Advance notice of proposed rulemaking (ANPRM).

SUMMARY: PHMSA is considering whether changes are needed to the regulations governing the safety of gas transmission pipelines. In particular, PHMSA is considering whether integrity management (IM) requirements should be changed, including adding more prescriptive language in some areas, and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. Among the specific issues PHMSA is considering concerning IM requirements is whether the definition of a high-consequence area (HCA) should be revised, and whether additional restrictions should be placed on the use of specific pipeline assessment methods. With respect to non-IM requirements, PHMSA is considering whether revised requirements are needed on new construction or existing pipelines concerning mainline valves, including valve spacing and installation of remotely operated or automatically operated valves; whether requirements for corrosion control of steel pipelines should be strengthened; and whether new regulations are needed to govern the safety of gathering lines and underground gas storage facilities. Additional issues PHMSA is considering are addressed in the **SUPPLEMENTARY INFORMATION** Section under background.

DATES: Persons interested in submitting written comments on this ANPRM must do so by December 2, 2011. PHMSA will consider late filed comments as far as practicable.

FOR FURTHER INFORMATION CONTACT: Mike Israni, by telephone at 202–366–4571, by fax at 202–366–4566, or by mail at U.S. DOT, PHMSA, 1200 New Jersey Avenue, SE., PHP–1, Washington, DC 20590–0001.

ADDRESSES: You may submit comments identified by the docket number PHMSA–2011–0023 by any of the following methods:

- *Web Site: http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *Fax:* 1–202–493–2251.
- *Mail:* Hand Delivery: U.S. DOT Docket Management System, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001 between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Instructions: If you submit your comments by mail, submit two copies. To receive confirmation that PHMSA received your comments, include a self-addressed stamped postcard.

Note: Comments are posted without changes or edits to *http://www.regulations.gov,* including any personal information provided. There is a privacy statement published on *http://www.regulations.gov.* A glossary of terms used in this document can be found at the following Web site: *http://primis.phmsa.dot.gov/comm/.*

SUPPLEMENTARY INFORMATION:

I. Background

Congress has authorized Federal regulation of the transportation of gas by pipeline under the Commerce Clause of the U.S. Constitution. The authorization is codified in the Pipeline Safety Laws (49 U.S.C. 60101 *et seq.*), a series of statutes that are administered by PHMSA. PHMSA promulgated comprehensive minimum safety standards for the transportation of gas by pipeline under the Pipeline Safety

Regulations (PSR; 49 CFR parts 190–199).

Congress established the current framework for regulating natural gas pipelines in the Natural Gas Pipeline Safety Act of 1968, Public Law 90–481, which has since been recodified at 49 U.S.C. 60101 *et seq.* That law delegated to DOT the authority to develop, prescribe, and enforce minimum Federal safety standards for the transportation of gas, including natural gas, flammable gas, or toxic or corrosive gas, by pipeline. Congress has since enacted additional legislation that is currently codified in the Pipeline Safety Laws.

In 1992, Congress required regulations be issued to define the term ''gathering line'' and establish safety standards for certain ''regulated gathering lines.'' In 1996, Congress directed that DOT conduct demonstration projects evaluating the application of risk management principles to pipeline safety regulations, and mandated that regulations be issued for the qualification and testing of certain pipeline personnel.

In 2002, Congress required that DOT issue regulations requiring operators of gas transmission pipelines to conduct risk analyses and to implement IM programs under which pipeline segments in HCAs would be subject to a baseline assessment within ten years and re-assessments at least every seven years. PHMSA administers compliance with these statutes and has promulgated comprehensive safety standards and regulations for the transportation of natural gas by pipeline. That includes regulations for the:

• Design and construction of new pipeline systems or those that have been relocated, replaced, or otherwise changed (subparts C and D of 49 CFR part 192).

• Protection of steel pipelines from the adverse effects of internal and external corrosion (subpart I of 49 CFR part 192).

• Pressure tests of new pipelines (subpart J of 49 CFR part 192).

• Operation and maintenance of pipeline systems, including establishing programs for public awareness and damage prevention, and managing the operation of pipeline control rooms (subparts L and M of 49 CFR part 192).

• Qualification of pipeline personnel (subpart N of 49 CFR part 192).

• Management of the integrity of pipelines in HCAs (subpart O of 49 CFR part 192).

The IM requirements of subpart O of 49 CFR part 192 apply to areas called high consequence areas or HCA's. An integrity management program is a documented set of policies, processes, and procedures that are implemented to ensure the integrity of a pipeline. In accordance with pipeline safety regulations for gas transmission pipelines (subpart O of 49CFR part 192) an operator's integrity management program must include, at a minimum, the following elements:

a. An identification of all high consequence areas;

b. A baseline assessment plan;

c. An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment and to evaluate the merits of additional preventive and mitigative measures for each covered segment;

d. A direct assessment plan, if applicable;

e. Provisions for remediating conditions found during an integrity assessment;

f. A process for continual evaluation and assessment;

g. If applicable, a plan for confirmatory direct assessment meeting the requirement;

h. Provisions for adding preventive and mitigative measures to protect the high consequence area;

i. A performance plan that includes performance measures;

j. Record keeping provisions;

k. A management of change process;

l. A quality assurance process;

m. A communication plan that includes procedures for addressing safety concerns raised by PHMSA or a State or local pipeline safety authority;

n. Procedures for providing (when requested) a copy of the operator's risk analysis or integrity management program to PHMSA or a State or local pipeline safety authority; and

o. Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks;

p. A process for identification and assessment of newly-identified high consequence areas.

A high consequence area is a location that is specially defined in the pipeline safety regulations as an area where pipeline releases could have greater consequences to health and safety or the environment. Regulations require a pipeline operator to take specific steps to ensure the integrity of a pipeline for which a release could affect an HCA and, thereby, the protection of the HCA. The PSR provide gas transmission pipeline operators with two options by which to identify which segments of their pipelines are in HCAs: (1) Reliance on class locations that historically have been part of the pipeline safety regulations for identifying pipelines in more-populated areas, or (2) determining segments for which a specified number of structures intended for human occupation or a so-called identified site (representing areas where people congregate) are located within the potential impact radius of a hypothetical pipeline rupture and subsequent explosion.

Other recent rulemaking have addressed different but related issues relative to pipeline safety. On October 18, 2010 (75 FR 63774) PHMSA published an ANPRM titled ''Pipeline Safety: Safety of On-Shore Hazardous Liquid Pipelines.'' In that rulemaking, PHMSA is considering whether changes are needed to the regulations covering hazardous liquid onshore pipelines. In particular, PHMSA sought comment on whether it should extend regulation to certain pipelines currently exempt from regulation; whether other areas along a pipeline should either be identified for extra protection or be included as additional HCAs for IM protection; whether to establish and/or adopt standards and procedures for minimum leak detection requirements for all pipelines; whether to require the installation of emergency flow restricting devices (EFRDs) in certain areas; whether revised valve spacing requirements are needed on new construction or existing pipelines; whether repair timeframes should be specified for pipeline segments in areas outside the HCAs that are assessed as part of the IM; and whether to establish and/or adopt standards and procedures for improving the methods of preventing, detecting, assessing and remediating stress corrosion cracking (SCC) in hazardous liquid pipeline systems.

On December 4, 2009, PHMSA issued the Distribution Integrity Management Final Rule, which extends the pipeline integrity management principles that were established for hazardous liquid and natural gas transmission pipelines, to the local natural gas distribution pipeline systems. This regulation, which became effective in August of 2011, requires operators of local gas distribution pipelines to evaluate the risks on their pipeline systems, to determine their fitness for service, and to take action to address those risks. For older gas distribution systems, the appropriate mitigation measures could involve major pipe rehabilitation, repair, and replacement programs. At a minimum, these measures are needed to requalify those systems as being fit for service.

II. Advance Notice of Proposed Rulemaking

PHMSA believes that the IM requirements applicable to gas transmission pipelines contained in the Pipeline Safety Regulations (49 CFR parts 190–199) have increased the level of safety associated with the transportation of gas in HCA's. Still, incidents with significant consequences continue to occur on gas transmission pipelines (*e.g.,* incident in San Bruno, CA September 9, 2010). PHMSA has also identified concerns during inspections of gas transmission pipeline operator IM programs that indicate a potential need to clarify and enhance some requirements. PHMSA is now considering whether additional safety measures are necessary to increase the level of safety for those pipelines that are in non-HCA areas as well as whether the current IM requirements need to be revised and enhanced to assure that they continue to provide an adequate level of safety in HCAs.

Within this ANPRM, PHMSA is seeking public comment on 14 specific topic areas in two broad categories.

1. Should IM requirements be revised and strengthened to bring more pipeline mileage under IM requirements and to better assure safety of pipeline segments in HCAs? Specific topics include:

• Modifying the definition of an HCA.
• Strengthening the Integrity Management requirements in part 192.
• Modifying repair criteria.
• Revising the requirements for collecting, validating, and integrating pipeline data.
• Making requirements related to the nature and application of risk models more prescriptive.
• Strengthening requirements for applying knowledge gained through the IM program.
• Strengthening requirements on the selection and use of assessment methods, including prescribing assessment methods for certain threats (such as manufacturing and construction defects, SCC, *etc.*) or in certain situations such as when certain knowledge is not available or data is missing.

2. Should non-IM requirements be strengthened or expanded to address other issues associated with pipeline system integrity? Specific topics include:

• Valve spacing and the need for remotely- or automatically-controlled valves.
• Corrosion control.
• Pipe with longitudinal weld seams with systemic integrity issues.
• Establishing requirements applicable to underground gas storage.
• Management of Change.
• Quality Management Systems (QMS).
• Exemptions applicable to [1] facilities installed prior to the regulations.
• Gathering lines.

Each topic is discussed in more detail in this document.

A. Modifying the Definition of HCA

Part 192 has historically included requirements delineating pipeline segments by class location based on the population density near the pipeline. Class locations are based on the number of buildings intended for human occupancy that exist within a ''class location unit,'' defined as an area extending 220 yards (100 meters) on either side of the centerline of any continuous one-mile (1.6 kilometers) length of pipeline. Class locations are defined in § 192.5 as:

• Class 1—10 or fewer buildings intended for human occupancy within a class location unit.
• Class 2—more than ten but less than 46 buildings intended for human occupancy.
• Class 3—46 or more buildings intended for human occupancy.
• Class 4—any class location unit where buildings with four or more stories are prevalent.

Part 192 provides additional protection for higher class location areas, principally through provisions that require pipe in these higher class locations to operate at lower stress levels.

With the advent of IM requirements, PHMSA introduced a new mechanism in part 192 to define pipeline segments to which additional requirements should apply based on the population at risk in the vicinity of the pipeline. HCAs are defined in § 192.903 using either of two methods. Operators are allowed to pick the method they use to identify their HCAs.

Method 1 builds on the traditional concept of class locations. Under this method, all pipeline segments in Class 3 and 4 locations are within an HCA. In addition, pipeline segments in Class 1 and 2 locations are within an HCA if an ''identified site'' is located within the ''potential impact circle.'' Identified sites are defined as areas in which 20 or more persons congregate for a specified number of days each year or facilities occupied by persons who are confined, of impaired mobility, or would be difficult to evacuate.

Method 2 defines HCAs based solely on potential impact circles. A potential impact circle is an estimated zone in which the failure of a pipeline could have significant impact on people or property. The radius of the potential impact circle is calculated using a formula specified in the regulations that is based on the diameter and operating pressure of the pipeline. A pipeline segment is identified as an HCA if the potential impact circle includes 20 or more buildings intended for human occupancy or an identified site, regardless of class location.

Some gas transmission pipeline operators do not collect data concerning the number of buildings within class location units along their pipeline, but rather design all of their pipelines as though they were in a Class 3 or 4 location. This approach is often used by operators of gas distribution companies that also operate small amounts of pipeline meeting part 192's definition as transmission pipeline. Method 1 was included in the definition of an HCA in deference to these operators, allowing them to avoid the additional costs associated with collecting data on nearby buildings that they have not previously collected. Method 2 was presumed to identify pipeline segments where incidents could produce high consequences more accurately and is typically used by pipeline operators who have collected data on local structures to determine class locations.

PHMSA regulates approximately 297,000 miles of onshore gas transmission pipelines. Of these, approximately 30,300 miles (10.2%) are in Class 2 locations, approximately 33,500 miles (11.3%) are in Class 3 locations, and approximately 1600 miles (0.54%) are in Class 4 locations. Operators have identified approximately 19,000 miles (6.4%) of gas transmission pipeline to be within an HCA.

IM requirements in subpart O of part 192 specify how pipeline operators must identify, prioritize, assess, evaluate, repair and validate; through comprehensive analyses, the integrity of gas transmission pipelines in HCAs. Although operators may voluntarily apply IM practices to pipeline segments that are not in HCAs, the regulations do not require operators to do so.

A gas transmission pipeline ruptured in San Bruno, California on September 9, 2010, resulting in eight deaths and considerable property damage. As a result of this event, public concern has been raised regarding whether safety requirements applicable to pipe in populated areas can be improved. PHMSA is thus considering expanding the definition of an HCA so that more

[1] As described below, these exemptions relate to allowable maximum operating pressure for pipelines that were in service before the initial gas pipeline safety regulations were published. These pipelines are commonly known as ''grandfathered'' pipelines.

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

[Docket No. PHMSA–2011–0023]

RIN 2137–AE72

Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking.

SUMMARY: This Notice of Proposed Rulemaking (NPRM) proposes to revise the Pipeline Safety Regulations applicable to the safety of onshore gas transmission and gathering pipelines. PHMSA proposes changes to the integrity management (IM) requirements and proposes changes to address issues related to non-IM requirements. This NPRM also proposes modifying the regulation of onshore gas gathering lines.

DATES: Persons interested in submitting written comments on this NPRM must do so by June 7, 2016.

ADDRESSES: You may submit comments identified by the docket number PHMSA–2011–0023 by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the online instructions for submitting comments.
- *Fax:* 1–202–493–2251.
- *Mail:* Hand Delivery: U.S. DOT Docket Management System, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590–0001 between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Instructions: If you submit your comments by mail, submit two copies. To receive confirmation that PHMSA received your comments, include a self-addressed stamped postcard.

Note: Comments are posted without changes or edits to *http://www.regulations.gov*, including any personal information provided. There is a privacy statement published on *http://www.regulations.gov*.

FOR FURTHER INFORMATION CONTACT: Mike Israni, by telephone at 202–366–4571, or by mail at U.S. DOT, PHMSA, 1200 New Jersey Avenue SE., PHP–30, Washington, DC 20590–0001.

SUPPLEMENTARY INFORMATION:

Outline of This Document

I. Executive Summary

A. Purpose of the Regulatory Action

PHMSA believes that the current regulatory requirements applicable to gas pipeline systems have increased the level of safety associated with the transportation of gas. Still, incidents with significant consequences and various causes continue to occur on gas pipeline systems. PHMSA has also identified concerns during inspections of gas pipeline operator programs that indicate a potential need to clarify and enhance some requirements. Based on this experience, this NPRM proposes additional safety measures to increase the level of safety for those pipelines that are not in HCAs as well as clarifications and selected enhancements to integrity management requirements to improve safety in HCAs.

On August 25, 2011, PHMSA published an Advance Notice of Proposed Rulemaking (ANPRM) to seek feedback and comments regarding the revision of the Pipeline Safety Regulations applicable to the safety of gas transmission and gas gathering pipelines. In particular, PHMSA requested comments regarding whether integrity management (IM) requirements should be changed and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements.

Subsequent to issuance of the ANPRM, the National Transportation Safety Board (NTSB) adopted its report on the San Bruno accident on August 30, 2011. The NTSB issued safety recommendations P–11–1 and P–11–2 and P–11–8 through -20 to PHMSA, and issued safety recommendations P–10–2 through -4 to Pacific Gas & Electric (PG&E), among others. Several of these NTSB recommendations related directly to the topics addressed in the August 25, 2011 ANPRM and have an impact on the proposed approach to rulemaking.

Also subsequent to issuance of the ANPRM, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act) was enacted on January 3, 2012. Several of the Act's statutory requirements related directly to the topics addressed in the August 25, 2011 ANPRM and have an impact on the proposed approach to rulemaking.

Congress has authorized Federal regulation of the transportation of gas by pipeline in the Pipeline Safety Laws (49 U.S.C. 60101 *et seq.*), a series of statutes that are administered by the DOT, PHMSA. PHMSA has used that authority to promulgate comprehensive minimum safety standards for the transportation of gas by pipeline.

Congress established the current framework for regulating pipelines transporting gas in the Natural Gas Pipeline Safety Act of 1968, Public Law 90–481. That law delegated to DOT the authority to develop, prescribe, and enforce minimum Federal safety standards for the transportation of gas, including natural gas, flammable gas, or toxic or corrosive gas, by pipeline. Congress has since enacted additional legislation that is currently codified in the Pipeline Safety Laws, including:

In 1992, Congress required regulations be issued to define the term ''gathering line'' and establish safety standards for certain ''regulated gathering lines,'' Public Law 102–508. In 1996, Congress directed that DOT conduct demonstration projects evaluating the application of risk management principles to pipeline safety regulation, and

mandated that regulations be issued for the qualification and testing of certain pipeline personnel, Public Law 104–304. In 2002, Congress required that DOT issue regulations requiring operators of gas transmission pipelines to conduct risk analyses and to implement IM programs under which pipeline segments in high consequence areas (HCA) would be subject to a baseline assessment within 10 years and re-assessments at least every seven years, and required that standards be issued for assessment of pipelines using direct assessment, Public Law 107–355.

B. Summary of the Major Provisions of the Regulatory Action in Question

PHMSA plans to address several of the topics in the ANPRM in separate rulemakings because of the diverse scope and nature of several NTSB recommendations and the statutory requirements of the Act that were covered in the ANPRM. This proposed rule addresses several IM topics, including: Revision of IM repair criteria for pipeline segments in HCAs to address cracking defects, non-immediate corrosion metal loss anomalies, and other defects; explicitly including functional requirements related to the nature and application of risk models currently invoked by reference to industry standards; explicitly specifying requirements for collecting, validating, and integrating pipeline data models currently invoked by reference to industry standards; strengthening requirements for applying knowledge gained through the IM Program models currently invoked by reference to industry standards; strengthening requirements on the selection and use of direct assessment methods models by incorporating recently issued industry standards by reference; adding requirements for monitoring gas quality and mitigating internal corrosion, and adding requirements for external corrosion management programs including above ground surveys, close interval surveys, and electrical interference surveys; and explicitly including requirements for management of change currently invoked by reference to industry standards. With respect to non-IM requirements, this NPRM proposes: A new ''moderate consequence areas'' definition; adding requirements for monitoring gas quality and mitigating internal corrosion; adding requirements for external corrosion management programs including above ground surveys, close interval surveys, and electrical interference surveys; additional requirements for management of change, including invoking the requirements of ASME/ANSI B31.8S, Section 11; establishing repair criteria for pipeline segments located in areas not in an HCA; and requirements for verification of maximum allowable operating pressure (MAOP) in accordance with new § 192.624 and for verification of pipeline material in accordance with new section § 192.607 for certain onshore, steel, gas transmission pipelines. This includes establishing and documenting MAOP if the pipeline MAOP was established in accordance with § 192.619(c) or the pipeline meets other criteria indicating a need for establishing MAOP.

In addition, this NPRM proposes modifying the regulation of onshore gas gathering lines. The proposed rulemaking would repeal the exemption for reporting requirements for gas gathering line operators and repeal the use of API RP 80 for determining regulated onshore gathering lines and add a new definition for ''onshore production facility/operation'' and a revised definition for ''gathering lines.'' The proposed rulemaking would also extend certain part 192 regulatory requirements to Type A lines in Class 1 locations for lines 8 inches or greater. Requirements that would apply to previously unregulated pipelines meeting these criteria would be limited to damage prevention, corrosion control (for metallic pipe), public education program, maximum allowable operating pressure limits, line markers, and emergency planning.

This NPRM also proposes requirements for additional topics that have arisen since issuance of the ANPRM. These include: (1) Requiring inspections by onshore pipeline operators of areas affected by an extreme weather event such as a hurricane or flood, landslide, an earthquake, a natural disaster, or other similar event; (2) revising the regulations to allow extension of the IM 7-year reassessment interval upon written notice per Section 5 of the Act; (3) adding a requirement to report each exceedance of the MAOP that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices per Section 23 of the Act; (4) adding requirements to ensure consideration of seismicity of the area in identifying and evaluating all potential threats per Section 29 of the Act; (5) adding regulations to require safety features on launchers and receivers for in-line inspection, scraper, and sphere facilities; and (6) incorporating consensus standards into the regulations for assessing the physical condition of in-service pipelines using in-line inspection, internal corrosion direct assessment, and stress corrosion cracking direct assessment.

The overall goal of this proposed rule is to increase the level of safety associated with the transportation of gas by proposing requirements to address the causes of recent incidents with significant consequences, clarify and enhance some existing requirements, and address certain statutory mandates of the Act and NTSB recommendations.[1]

C. Costs and Benefits

Consistent with Executive Orders 12866 and 13563, PHMSA has prepared an assessment of the benefits and costs of the proposed rule as well as reasonable alternatives. PHMSA is publishing the Preliminary Regulatory Impact Analysis (PRIA) for this proposed rule simultaneously with this document, and it is available in the docket.

PHMSA estimates the total (15-year) present value of benefits from the proposed rule to be approximately $3,234 to $3,738 million[2] using a 7% discount rate ($4,050 to $4,663 million using a 3% discount rate) and the present value of costs to be approximately $597 million using a 7% discount rate ($711 million using a 3% discount rate). The table below summarizes the average annual present value benefits and costs by topic area. The majority of benefits reflect cost savings from material verification (processes to determine maximum allowable operating pressure for segments for which records are inadequate) under the proposed rule compared to existing regulations; the range in these benefits reflects different effectiveness assumptions for estimating safety benefits. Costs reflect primarily integrity verification and assessment costs (pressure tests, inline inspection, and direct assessments). The proposed gas gathering regulations account for the next largest portion of benefits and costs and primarily reflect safety provisions and associated risk reductions on previously unregulated lines.

[1] PHMSA plans to initiative separate rulemaking to address other topics included in the ANPRM and that would implement other requirements of the Act and NTSB recommendations.

[2] Range reflects uncertainty in defect failure rates for Topic Area 1.

SUMMARY OF AVERAGE ANNUAL PRESENT VALUE BENEFITS AND COSTS [1]

[Millions; 2015$]

Topic area	7% discount rate		3% discount rate	
	Benefits	Costs	Benefits	Costs
Re-establish MAOP, verify material properties, and integrity assessments outside HCAs	$196.9–$230.5	$17.8	$247.8–$288.6	$22.0
Integrity management process clarifications	n.e.	2.2	n.e.	1.3
Management of change process improvement	1.1	0.7	1.2	0.8
Corrosion control	5.5	6.3	5.9	7.9
Pipeline inspection following extreme events	0.3	0.1	0.3	0.1
MAOP exceedance reports and records verification	n.e.	0.2	n.e.	0.2
Launcher/receiver pressure relief	0.4	0.0	0.6	0.0
Gas gathering regulations	11.3	12.6	14.2	15.1
Total	215.6–249.2	39.8	270–310.8	47.4

HCA = high consequence area.
MAOP = maximum allowable operating pressure.
n.e. = not estimated.
[1] Total over 15-year study period divided by 15. Additional costs to states estimated not to exceed $1.5 million per year. Range of benefits reflects range in estimated defect failure rates.
[2] Break even value of benefits, based on the average consequences for incidents in high consequence areas, would equate to less than one incident averted over the 15-year study period.

For the seven percent discount rate scenario, approximately 13 percent of benefits are due to safety benefits from incidents averted, 82 percent represent cost savings from MAOP verification in Topic Area 1, and four percent are attributable to reductions in greenhouse gas emissions. (For the three percent discount rate scenario, these percentages are approximately 13, 83, and 3 percent, respectively.)

II. Background

A. Detailed Overview

Introduction

The significant and expected growth in the nation's production and use of natural gas is placing unprecedented demands on the nation's pipeline system, underscoring the importance of moving this energy product safely and efficiently. With changing spatial patterns of natural gas production and use and an aging pipeline network, improved documentation and data collection are increasingly necessary for the industry to make reasoned safety choices and for preserving public confidence in its ability to do so. Congress recognized these needs when passing the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, calling for an examination of a broad range of issues pertaining to the safety of the nation's pipeline network, including a thorough application of the risk-based integrity assessment, repair, and validation system known as ''integrity management'' (IM).

This proposed rulemaking advances the goals established by Congress in the 2011 Act, which are consistent with the emerging needs of the natural gas pipeline system. This proposed rule also advances an important discussion about the need to adapt and expand risk-based safety practices in light of changing markets and a growing national population whose location choices increasingly encroach on existing pipelines. As some severe pipeline accidents have occurred in areas outside of high consequence areas (HCA) where the application of IM principles is not required, and as gas pipelines continue to experience failures from causes that IM was intended to address, this conversation is increasingly important.

This proposed rule strengthens protocols for IM, including protocols for inspections and repairs, and improves and streamlines information collection to help drive risk-based identification of the areas with the greatest safety deficiencies. Further, this proposed rule establishes requirements to periodically assess and extend aspects of IM to pipeline segments in locations where the surrounding population is expected to potentially be at risk from an incident. Even though these segments are not within currently defined HCAs, they could be located in areas with significant populations where incidents could have serious consequences. This change would facilitate prompt identification and remediation of potentially hazardous defects and anomalies while still allowing operators to make risk-based decisions on where to allocate their maintenance and repair resources.

Natural Gas Infrastructure Overview

The U.S. natural gas pipeline network is designed to transport natural gas to and from most locations in the lower 48 States. Approximately two-thirds of the lower 48 States depend almost entirely on the interstate transmission pipeline system for their supplies of natural gas.[3] To envision the scope of the nation's natural gas pipeline infrastructure, it is best to consider it in three interconnected parts that together transport natural gas from the production field, where gas is extracted from underground, to its end users, where the gas is used as an energy fuel or chemical feedstock. These three parts are referred to as gathering, transmission, and distribution systems. Because this proposed rule applies only to gas gathering and transmission lines, this document will not discuss natural gas distribution infrastructure and its associated issues. Currently, there are over 11,000 miles of onshore gas gathering pipelines and 297,814 miles of onshore gas transmission pipelines throughout the U.S.[4]

Gas gathering lines are pipelines used to transport natural gas from production sites to central collection points, which are often gas treatment plants where pipeline-quality gas is separated from petroleum liquids and various impurities. Historically, these lines were of smaller diameters than gas transmission lines and operated at lower pressures. However, due to changing demand factors, some gathering lines are being constructed with diameters equal to or larger than typical transmission lines and are being operated at much higher pressures.

Transmission pipelines primarily transport natural gas from gas treatment

[3] U.S. Department of Energy, ''Appendix B: Natural Gas,'' *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,* p. NG–28, April 2015.

[4] US DOT Pipeline and Hazardous Materials Safety Administration Data as of 9/25/2015.

plants and gathering systems to bulk customers, local distribution networks, and storage facilities. Transmission pipelines are typically made of steel and can range in size from several inches to several feet in diameter. They can operate over a wide range of pressures, from relatively low (200 pounds per square inch) to over 1,500 pounds per square inch gage (psig). They can operate within the geographic boundaries of a single State, or span hundreds of miles, crossing one or more State lines.

Regulatory History

PHMSA and its State partners regulate pipeline safety for jurisdictional [5] gas gathering, transmission, and distribution systems under minimum Federal safety standards authorized by statute [6] and codified in the Pipeline Safety Regulations at 49 CFR parts 190–199.

Federal regulation of gas pipeline safety began in 1968 with the creation of the Office of Pipeline Safety and their subsequent issuance of interim minimum Federal safety standards for gas pipeline facilities and the transportation of natural and other gas in accordance with the Natural Gas Pipeline Safety Act of 1968 (Pub. L. 90–481). These Federal safety standards were upgraded several times over the following decades to address different aspects of natural gas transportation by pipeline, including construction standards, pipeline materials, design standards, class locations, corrosion control, and maximum allowable operating pressure (MAOP).

These original Pipeline Safety Regulations were not designed with risk-based regulations in mind. In the mid-1990s, following models from other industries such as nuclear power, PHMSA started to explore whether a risk-based approach to regulation could improve safety of the public and the environment. During this time, PHMSA found that many operators were performing forms of IM that varied in scope and sophistication but that there were no minimum standards or requirements.

In response to a hazardous liquid incident in Bellingham, WA, in 1999 that killed 3 people and a gas transmission incident in Carlsbad, NM, in 2000 that killed 12, IM regulations for gas transmission pipelines were finalized in 2004.[7] The primary goal of the 2004 IM regulations was to provide a structure to operators for focusing their resources on improving pipeline integrity in the areas where a failure would have the greatest impact on public safety. Further objectives included accelerating the integrity assessment of pipelines in HCAs, improving IM systems within companies, improving the government's ability to review the adequacy of integrity programs and plans, thus providing increased public assurance in pipeline safety.

The IM regulations specify how pipeline operators must conduct comprehensive analyses to identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines in HCAs, which are typically areas where population is highly concentrated. Currently, approximately 7 percent of onshore gas transmission pipeline mileage is located in HCAs. PHMSA and state inspectors review operators' written IM programs and associated records to verify that the operators have used all available information about their pipelines to assess risks and take appropriate actions to mitigate those risks.

Since the implementation of the IM regulations more than 10 years ago, many factors have changed. Most importantly, sweeping changes in the natural gas industry have caused significant shifts in supply and demand, and the nation's relatively safe but aging pipeline network faces increased pressures from these changes as well as from the increased exposure caused by a growing and geographically dispersing population. Long-identified pipeline safety issues, some of which IM set out to address, remain problems. Infrequent but severe accidents indicate that some pipelines continue to be vulnerable to failures stemming from outdated construction methods or materials. Some severe pipeline accidents have occurred in areas outside HCAs where the application of IM principles is not required. Gas pipelines continue to experience failures from causes that IM was intended to address, such as corrosion, and the measures currently in use have not always been effective in identifying and preventing these causes of pipeline damage.

There is a pressing need for an improved strategy to protect the safety and integrity of the nation's pipeline system. Following a significant pipeline incident in 2010 at San Bruno, CA, in which 8 people died and more than 50 people were injured, Congress, the National Transportation Safety Board (NTSB), and the Government Accountability Office (GAO) charged PHMSA with improving IM. Comments from a 2011 advanced notice of proposed rulemaking (ANPRM) suggested there were many common-sense improvements that could be made to IM, as well as a clear need to extend certain IM provisions to pipelines not now covered by the IM regulations. A large portion of the transmission pipeline industry has voluntarily committed to extending certain IM provisions to non-HCA pipe, which clearly underscores the common understanding of the need for this strategy.

Through this proposed rule, PHMSA is taking action to deliver a comprehensive strategy to improve gas transmission pipeline safety and reliability, through both immediate improvements to IM and a long-range review of risk management and information needs, while also accounting for a changing landscape and a changing population.

Supply Changes

The U.S. natural gas industry has undergone changes of unprecedented magnitude and pace, increasing production by 33 percent between 2005 and 2013, from 19.5 trillion cubic feet per year to 25.7 trillion cubic feet per year.[8] Driving these changes has been a shift towards the production of "unconventional" natural gas supplies using improved technology to extract gas from low permeability shales. The increased use of directional drilling and improvements to a long-existing industrial technique—hydraulic fracturing, which began as an experiment in 1947—made the recovery of unconventional natural gas easier and economically viable. This shift in production has decreased prices and spurred tremendous increases in the use of natural gas.

While conventional natural gas production in the U.S. has fallen over the past decade by about 14 billion cubic feet per day, overall natural gas production has grown due to increased unconventional shale gas production. In 2004, unconventional shale gas accounted for about 5 percent of the total natural gas production in the U.S. Since then, unconventional shale gas

[5] Typically, onshore pipelines involved in the "transportation of gas"—see 49 CFR 192.1 and 192.3 for detailed applicability.

[6] Title 49, United States Code, Subtitle VIII, Pipelines, Sections 60101, *et. seq.*

[7] [68 FR 69778, Dec. 15, 2003] 49 CFR part 192 [Docket No. RSPA–00–7666; Amendment 192–95] Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines).

[8] U.S. Department of Energy, "Appendix B: Natural Gas," *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,* p. NG–2, April 2015.

production has increased more than tenfold from 2.7 Bcf/d to about 35.0 Bcf/d in 2014 [9] and now accounts for about half of overall gas production in the U.S.[10]

This increase in unconventional natural gas production shifted production away from traditional gas-rich regions towards onshore shale gas regions. In 2004, the Gulf of Mexico produced about 20 percent of the nation's natural gas supply, but by2013, that number had fallen to 5 percent. During that same time, Pennsylvania's share of production grew from 1 percent to 13 percent. An analysis conducted by the Department of Energy's (DOE) Office of Energy Policy and Systems Analysis projects that the most significant increases in production through 2030 will occur in the Marcellus and Utica Basins in the Appalachian Basin,[11] which will continue to fuel growth in natural gas production from current levels of 66.5 Bcf/d to more than 93.5 Bcf/d.[12]

Demand Changes

The recent increase in domestic natural gas production has led to decreased gas price volatility and lower average prices.[13] In 2004, the outlook for natural gas production and demand growth was weak. Monthly average spot prices at Henry Hub [14] were high, fluctuating between $4 per million British thermal units (Btu) and $7 per million Btu. Prices rose above $11 per million Btu for several months in both 2005 and 2008.[15] Since 2008, after production shifted to onshore unconventional shale resources, and price volatility fell away following the Great Recession, natural gas has traded between about $2 per million Btu and $5 per million Btu.[16]

These historically low prices for this commodity are fueling tremendous consumption growth and changes in markets and spatial patterns of consumption. A shift towards natural gas-fueled electric power generation is helping to serve the needs of the nation's growing population while helping reduce greenhouse gas emissions, and American industries are taking advantage of cheap energy by investing in onshore production capacity, while also exploring economic opportunities for international energy export.

Plentiful domestic natural gas supply and comparatively low natural gas prices have changed the economics of electric power markets.[17] Further, new environmental standards at the local, state, regional, and Federal levels have encouraged switching to fuels with lower emissions profiles, including natural gas and renewables. U.S. natural gas consumption for power generation grew from 15.8 billion cubic feet per day (Bcf/d) in 2005 to 22.2 Bcf/d in 2013, and demand is projected to increase by another 8.9 Bcf/d by 2030.[18] Net gas-fired electricity generation increased 73 percent nationally from 2003 to 2013, and natural gas-fired power plants accounted for more than 50 percent of new utility-scale generating capacity added in 2013. To accommodate continued future growth in natural gas-fueled power, changes in pipeline infrastructure will be needed, including reversals of existing pipelines; additional lines to gas-fired generators; looping of the existing network, where pipelines are laid parallel to one another along a single right-of-way to increase capacity; and potentially new pipelines as well.

Further, the increased availability of low-cost natural gas has brought jobs back to American soil, and increasing investment in projects designed to take advantage of the significant increase in supplies of low-cost gas available in the U.S. suggests this trend will continue.[19] Moreover, low domestic prices and high international prices have made natural gas export increasingly attractive to American businesses. The Federal Energy Regulatory Commission, as of September 2015, estimated U.S. LNG prices at $2.25–$2.41 per million Btu, while prices in areas of Asia, Europe, and South America ranged from $6.30 to $7.62 per million Btu.[20] Due to high capital investment barriers and coordination difficulties between pipeline shippers, the maritime shipping industry, and pipeline operators, there are not enough ships and processing facilities to transport enough LNG to equalize prices. Taking advantage of these price differentials, liquefied natural gas exporting terminals in the U.S. and British Columbia, Canada, are projected to demand between 5.1 Bcf/d and 8.3 Bcf/d of gas by 2030.[21]

Increasing Pressures on the Existing Pipeline System Due to Supply and Demand Changes

Despite the significant increase in domestic gas production, the widespread distribution of domestic gas demand, combined with significant flexibility and capacity in the existing transmission system, mitigates the level of pipeline expansion and investment required to accommodate growing and shifting demand. Some of the new gas production is located near existing or emerging sources of demand, which reduces the need for additional natural gas pipeline infrastructure. In many instances where new natural gas pipelines are needed, the network is being expanded by participants pursuing lowest-cost options to move product to market—often making investments to enhance network capacity on existing lines rather than increasing coverage through new infrastructure. Where this capacity is not increasing via additional mileage, it is increasing through larger pipeline diameters or higher operating pressures. In short, the nation's existing, and in many cases, aging, pipeline system is facing the full brunt of this dramatic increase in natural gas supply and the shifting energy needs of the country.

The U.S. Energy Information Administration estimates that between 2004 and 2013, the natural gas industry spent about $56 billion expanding the natural gas pipeline network. Between 2008 and 2013, pipeline capacity additions totaled more than 110 Bcf/d.[22] Despite this increase in capacity, gas transmission mileage decreased from 299,358 miles in 2010 to 298,287 miles in 2013.

Building new infrastructure, or replacing and modernizing old infrastructure, is expensive and requires a long lead-time for planning. Frequently, the most inexpensive way to move new production to demand centers is by using available existing infrastructure. For several reasons, the U.S.'s extensive pre-existing gas network is currently underutilized: (1) Pipelines are long-lived assets that reflect historic supply and demand trends; (2) pipelines often are sized to meet high initial production levels and

[9] *Id.*, at NG–7.

[10] *Id.*

[11] *Id.*, at NG–6.

[12] *Id.*

[13] *Id.*, at NG–11.

[14] Henry Hub is a Louisiana natural gas distribution hub where conventional Gulf of Mexico natural gas can be directed to gas transmission lines running to different parts of the country. Gas bought and sold at the Henry hub serves as the national benchmark for U.S. natural gas prices. (*Id.*, at NG–29, NG–30).

[15] Energy Information Administration, Natural Gas Spot and Futures Prices, *http://www.eia.gov/dnav/ng/ng_pri_fut_s1_m.htm*, retrieved 14 October 2015.

[16] *Id.*, at NG–11.

[17] *Id.*, at NG–9.

[18] *Id.*

[19] *Id.*, at NG–10.

[20] *https://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf.*

[21] U.S. Department of Energy, ''Appendix B: Natural Gas,'' *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure*, p. NG–11, April 2015.

[22] *Id.*, at NG–31.

have excess long-term capacity due to changing economics; and (3) pipelines that were built specifically to provide gas to residential and commercial consumers in cold-weather regions but not for power generation are often under-utilized during off-peak seasons.

In cases where utilization of the existing pipeline network is high, the next most cost-effective solution is to add capacity to existing lines via compression. While this is technically a form of infrastructure investment, it is less costly, faster, and simpler for market participants in comparison to building a new pipeline. Adding compression, however, may raise average pipeline operating pressures, exposing previously hidden defects.

Developers also recognize that building new pipelines is challenging due to societal fears and cost, so new pipelines are typically designed in such a way that they can handle additional capacity if needed. In New England, new pipeline projects have been proposed to address pending supply constraints and higher prices. However, public acceptance presents a substantial challenge to natural gas pipeline development. Investments and proposals to pay for new natural gas transmission pipeline capacity and services often face significant challenges in determining feasible rights of way and developing community support for the projects.

Data Challenges

Because there is so much emphasis on using the existing pipeline system to meet the country's energy needs, it is increasingly important for that system to be safe and efficient. In order to keep the public safe and to assure the nation's energy security, operators and regulators must have an intimate understanding of the threats to and operations of the entire pipeline system.

Data gathering and integration are important elements of good IM practices, and while many strides have been made over the years to collect more and better data, several data gaps still exist. Ironically, the comparatively positive safety record of the nation's pipeline system to date makes it harder to quantify some of these gaps. Over the 20-year period of 1995–2014, transmission facilities accounted for 42 fatalities and 174 injuries, or about one-seventh of the total fatalities and injuries on the nation's natural gas pipeline system.[23] Over the 4-year period of 2011–2014, there was only 1 transmission-related fatality. Fortunately, there have been only limited ''worst-case scenarios'' to evaluate for cost/benefit analysis of measures to improve safety, so there are limited bases for projecting the possible impacts of low-probability, high-consequence events.

On September 9, 2010, a 30-inch-diameter segment of an intrastate natural gas transmission pipeline owned and operated by the Pacific Gas and Electric Company ruptured in a residential area of San Bruno, California. The rupture produced a crater about 72 feet long by 26 feet wide. The section of pipe that ruptured, which was about 28 feet long and weighed about 3,000 pounds, was found 100 feet south of the crater. The natural gas that was released subsequently ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area.

The San Bruno incident exposed several problems in the way data on pipeline conditions is collected and managed, showing that many operators have inadequate records regarding the physical and operational characteristics of their pipelines. Many of these records are necessary for the correct setting and validation of MAOP, which is critically important for providing an appropriate margin of safety to the public.

Much of operator and PHMSA's data is obtained through testing and inspection under IM requirements. However, this testing can be expensive, and the approaches to obtaining data that are most efficient over the long term may require significant upfront costs to modernize pipes and make them suitable for automated inspection. As a result, there continue to be data gaps that make it hard to fully understand the risks to and the integrity of the nation's pipeline system.

To assess a pipeline's integrity, operators generally choose between three methods of testing a pipeline: Inline inspection (ILI), pressure testing, and direct assessment (DA). There is a marked difference in the distribution of assessment methods between interstate and intrastate pipelines. In 2013, we estimate that about two-thirds of interstate pipeline mileage was suitable for in-line inspection, compared to only about half of intrastate pipeline mileage. Because a larger percentage of intrastate pipelines are unable to accommodate ILI tools, intrastate operators use more pressure testing and DA than interstate operators.

ILIs are performed by using special tools, sometimes referred to as ''smart pigs,'' which are usually pushed through a pipeline by the pressure of the product being transported. As the tool travels through the pipeline, it identifies and records potential pipe defects or anomalies. Because these tests can be performed with product in the pipeline, the pipeline does not have to be taken out of service for testing to occur, which can prevent excessive cost to the operator and possible service disruptions to consumers. Further, ILI is a non-destructive testing technique, and it can be less costly on a per-unit basis to perform than other assessment methods.

Pressure tests are typically used by pipeline operators as a means to determine the integrity (or strength) of the pipeline immediately after construction and before placing the pipeline in service, as well as periodically during a pipeline's operating life. In a pressure test, a test medium inside the pipeline is pressurized to a level greater than the normal operating pressure of the pipeline. This test pressure is held for a number of hours to ensure there are no leaks in the pipeline.

Direct assessment (DA) is the evaluation of various locations on a pipeline for corrosion threats. Operators will review records, indirectly inspect the pipeline, or use mathematical models and environmental surveys to find likely locations on a pipeline where corrosion might be occurring. Areas that are likely to have suffered from corrosion are subsequently excavated and examined. DA can be prohibitively expensive to use unless targeting specific locations, which may not give an accurate representation of the condition of lengths of entire pipeline segments.

Ongoing research and industry response to the ANPRM[24] appear to indicate that ILI and spike hydrostatic pressure testing is more effective than DA for identifying pipe conditions that are related to stress corrosion cracking defects. Both regulators and operators have expressed interest in improving ILI methods as an alternative to hydrostatic testing for better risk evaluation and management of pipeline safety. Hydrostatic pressure testing can result in substantial costs, occasional disruptions in service, and substantial methane emissions due to the routine evacuation of natural gas from pipelines prior to tests. Further, many operators prefer not to use hydrostatic pressure tests because it can potentially be a

[23] PHMSA, Pipeline Incident 20-Year Trends, *http://www.phmsa.dot.gov/pipeline/library/data-stats/pipelineincidenttrends*.

[24] ''Pipeline Safety: Safety of Gas Transmission Pipelines—Advanced Notice of Proposed Rulemaking,'' 76 FR 5308; August 25, 2011.

destructive method of testing.[25] ILI testing can obtain data along a pipeline not otherwise obtainable via other assessment methods, although this method also has certain limitations.

In this proposed rulemaking, PHMSA would expand the range of permissible assessment methods while imposing new requirements to guide operators' selection of appropriate methods. Allowing alternatives to hydrostatic testing (including ILI technologies), combined with further research and development to make ILI testing more accurate, could help to drive innovation in pipeline integrity testing technologies. This could eventually lead to improved safety and system reliability through better data collection and assessment.

Increased and Changing Use, Coupled With Age, Exposure to Weather, and Other Factors Can Increase the Risk of Pipeline Incidents

While the existing pipeline network's capacity is expected to bear the brunt of the increasing demand for natural gas in this country, due in part due to the location of new gas resources, new production patterns are causing unique concerns for some pipeline operators. The significant growth of production outside the Gulf Coast region—especially in Pennsylvania and Ohio—is causing a reorientation of the nation's transmission pipeline network. The most significant of these changes will require reversing flows on pipelines to move Marcellus and Utica gas to the southeastern Atlantic region and the Midwest.

Reversing a pipeline's flow can cause added stresses on the system due to changes in pressure gradients, flow rates, and product velocity, which can create new risks of internal corrosion. Occasional failures on natural gas transmission pipelines have occurred after operational changes that include flow reversals and product changes. PHMSA has noticed a large number of recent or proposed flow reversals and product changes on a number of gas transmission lines. In response to this phenomenon, PHMSA issued an Advisory Bulletin notifying operators of the potentially significant impacts such changes may have on the integrity of a pipeline.[26]

Further, the rise of shale gas production is altering not just the extent, but also the characteristics of the nation's gas gathering systems. Gas fields are being developed in new geographic areas, thus requiring entirely new gathering systems and expanded networks of gathering lines. Producers are employing gathering lines with diameters as large as 36 inches and maximum operating pressures up to 1480 psig, far exceeding historical design and operating pressure of typical gathering lines and making them similar to large transmission lines. Most of these new gas gathering lines are unregulated, and PHMSA does not collect incident data or report annual data on these unregulated lines.

However, PHMSA is aware of incidents that show gathering lines are subject to the same sorts of failures common to other pipelines that the agency does regulate. For example, on November 14, 2008, three homes were destroyed and one person was injured when a gas gathering line ruptured in Grady County, OK. On June 8, 2010, two workers died when a bulldozer struck a gas gathering line in Darrouzett, TX, and on June 29, 2010, three men working on a gas gathering line in Grady County, OK, were injured when it ruptured. The dramatic expansion in natural gas production and changes in typical gathering line characteristics require PHMSA to review its regulatory approach to gas gathering pipelines to address new safety and environmental risks.

In addition to demands placed on the nation's pipeline system due to increased and changing use, there are many other factors—including recurring issues that IM was initially developed to address—that affect the integrity of the nation's pipelines.

Data indicate that some pipelines continue to be vulnerable to issues stemming from outdated construction methods or materials. Much of the older line pipe in the nation's gas transmission infrastructure was made before the 1970s using techniques that have proven to contain latent defects due to the manufacturing process. For example, line pipe manufactured using low frequency electric resistance welding is susceptible to seam failure. Because these manufacturing techniques were used during the time before the Federal gas regulations were issued, many of those pipes are subsequently exempt from certain regulations, most notably the requirement to pressure test the pipeline or otherwise verify its integrity to establish MAOP. A substantial amount of this type of pipe is still in service. The IM regulations include specific requirements for evaluating such pipe if located in HCAs, but infrequent-yet-severe failures that are attributed to longitudinal seam defects continue to occur. The NTSB's investigation of the San Bruno incident determined that the pipe failed due to a similar defect. Additionally, between 2010 and 2014, fifteen other reportable incidents were attributed to seam failures, resulting in over $8 million of property damage.

The nation's pipeline system also faces a greater risk from failure due to extreme weather events such as hurricanes, floods, mudslides, tornadoes, and earthquakes. A 2011 crude oil spill into the Yellowstone River near Laurel, MT, was caused by channel migration and river bottom scour, leaving a large span of the pipeline exposed to prolonged current forces and debris washing downstream in the river. Those external forces damaged the exposed pipeline. In October 1994, flooding along the San Jacinto River led to the failure of eight hazardous liquid pipelines and also undermined a number of other pipelines. The escaping products were ignited, leading to smoke inhalation and burn injuries of 547 people. From 2003 to 2013, there were 85 reportable incidents in which storms or other severe natural force conditions damaged pipelines and resulted in their failure. Operators reported total damages of over $104M from these incidents. PHMSA has issued several Advisory Bulletins to operators warning about extreme weather events and the consequences of flooding events, including river scour and river channel migration.

Considering recent incidents and many of the factors outlined above, PHMSA believes IM has led to several improvements in managing pipeline safety, yet the agency believes there is still more to do to improve the safety of natural gas transmission pipelines and ensure public confidence.

Challenges to Modernization and Historical Problems Underscore the Need for a Clear Strategy To Protect the Safety and Integrity of the Nation's Pipeline System

The current IM program is both a set of regulations and an overall regulatory approach to improve pipeline operators' ability to identify and mitigate the risks to their pipeline systems. The objectives of IM are to accelerate and improve the quality of integrity assessments, promote more rigorous and systematic management of integrity, strengthen oversight, and increase public confidence. On the operator level, an IM program consists of multiple

[25] National Transportation Safety Board, "Pacific Gas and Electric Company; Natural Gas Transmission Pipeline Rupture and Fire; San Bruno, California; September 9, 2010," *Pipeline Accident Report NTSB/PAR–11–01,* Page 96, 2011.

[26] "Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes, and Conversion to Service," *ADB PHMSA–2014–0040,* 79 FR 56121; September 18, 2014.

components, including adopting procedures and processes to identify HCAs, determining likely threats to the pipeline within the HCA, evaluating the physical integrity of the pipe within the HCA, and repairing or remediating any pipeline defects found. Because these procedures and processes are complex and interconnected, effective implementation of an IM program relies on continual evaluation and data integration.

The initial definition for HCAs was finalized on August 6, 2002,[27] providing concentrations of populations with corridors of protection spanning 300, 660, or 1,000 feet, depending on the diameter and MAOP of the particular pipeline.[28] In a later NPRM,[29] PHMSA proposed changes to the definition of a HCA by introducing the concept of a covered segment, which PHMSA defined as the length of gas transmission pipeline that could potentially impact an HCA.[30] Previously, only distances from the pipeline centerline related to HCA definitions. PHMSA also proposed using Potential Impact Circles, Potential Impact Zones, and Potential Impact Radii (PIR) to identify covered segments instead of a fixed corridor width. The final Gas Transmission Pipeline Integrity Management Rule, incorporating the new HCA definition, was issued on December 15, 2003.[31]

The incident at San Bruno in 2010 motivated a comprehensive reexamination of gas transmission pipeline safety. Congress responded to concerns in light of the San Bruno incident by passing the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which directed the DOT to reexamine many of its safety requirements, including the expansion of IM regulations for transmission pipelines.

Further, both the NTSB and the GAO issued several recommendations to PHMSA to improve its IM program and pipeline safety. The NTSB noted, in a 2015 study,[32] that IM requirements have reduced the rate of failures due to deterioration of pipe welds, corrosion, and material failures. However, pipeline incidents in high-consequence areas due to other factors increased between 2010 and 2013, and the overall occurrence of gas transmission pipeline incidents in high-consequence areas has remained stable. The NTSB also found many types of basic data necessary to support comprehensive probabilistic modeling of pipeline risks are not currently available.

Many of these mandates and recommendations caused PHMSA to evaluate whether IM system requirements, or elements thereof, should be expanded beyond HCAs to afford protection to a larger percentage of the nation's population. Additionally, several of these mandates and recommendations asked PHMSA to enhance the existing IM regulations by addressing MAOP verification, inadequate operator records, legacy pipe issues, and inadequate integrity assessments. Further, PHMSA was charged with reducing data gaps and improving data integration, considering the regulatory framework for gas gathering systems, and deleting the ''grandfather clause'' to require all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic spike pressure test. This proposed rule addresses several of the recommendations from the 2015 study including P–15–18 (IM–ILI capability), P–15–20 (IM–ILI tools), P–15–21 (IM–Direct Assessments), and P–21 (IM–Data Integration).

PHMSA Is Delivering a Comprehensive Strategy To Protect the Nation's Pipeline System While Accounting for a Changing Landscape and a Changing Population

To address these statutory mandates, the post-San Bruno NTSB and GAO recommendations, and other pipeline safety mandates, PHMSA posed a series of questions to the public in the context of an August 2011 ANPRM titled ''Pipeline Safety: Safety of Gas Transmission Pipelines'' (PHMSA–2011–0023). In that document, PHMSA asked whether the regulations governing the safety of gas transmission pipelines needed changing. In particular, PHMSA asked whether IM requirements should be changed, including through adding more prescriptive language in some areas, and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. Among the specific issues PHMSA considered concerning IM requirements were whether the definition of an HCA should be revised, and whether additional restrictions should be placed on the use of specific pipeline assessment methods. In the ANPRM, PHMSA also considered changes to non-IM requirements, including valve spacing and installation, corrosion control, and whether regulations for gathering lines needed to be modified.

PHMSA received 103 comments in response to the ANPRM, which are summarized in more detail later in this document. Feedback from the ANPRM helped to identify a series of common-sense improvements to IM, including improvements to assessment goals such as integrity verification, MAOP verification, and material documentation; clarified repair criteria; clarified protocol for identifying threats, risk assessments and management, and prevention and mitigation measures; expanded and enhanced corrosion control; requirements for inspecting pipelines after incidents of extreme weather; and new guidance on how to calculate MAOP in order to set operating parameters more accurately and predict the risks of an incident.

Many of these aspects of IM have been an integral part of PHMSA's expectations since the inception of the IM program. As specified in the first IM rule, PHMSA expects operators to start with an IM framework, evolve a more detailed and comprehensive IM program, and continually improve their IM programs as they learn more about the IM process and the material condition of their pipelines through integrity assessments. This NPRM's proposals regarding operators' processes for implementing IM reflect PHMSA's expectations regarding the degree of progress operators should be making, or should have made, during the first 10 years of IM program implementation.

To address issues involving the increased risk posed by larger-diameter, higher-pressure gathering lines, PHMSA is proposing to issue requirements for certain currently unregulated gas gathering pipelines that are intended to prevent the most frequent causes of failure—corrosion and excavation damage—and to improve emergency response preparedness. Minimum Federal safety standards would also bring an appropriate level of consistency to the current mix of regulations that differ from state to state.

[27] ''Pipeline Safety: High Consequence Areas for Gas Transmission Pipelines,'' *Final rule,* 67 FR 50824; August 6, 2002.

[28] The influence of the existing class location concept on the early definition of HCAs is evident from the use of class locations themselves in the definition, and the use of fixed 660 ft. distances, which corresponds to the corridor width used in the class location definition. This concept was later significantly revised, as discussed later, in favor of a variable corridor width (referred to as the Potential Impact Radius) based on case-specific pipe size and operating pressure.

[29] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines),'' *Notice of Proposed Rulemaking,* 68 FR 4278; January 28, 2003.

[30] HCA and PIR definitions are in 49 CFR 192.903.

[31] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines),'' *Final rule,* 68 FR 69778; December 15, 2003.

[32] National Transportation Safety Board, ''Safety Study: Integrity Management of Gas Transmission Pipelines in High Consequence Areas,'' *NTSB SS–15/01,* January 27, 2015.

PHMSA believes these proposed changes will improve the safety and protection of pipeline workers, the public, property, and the environment by improving the detection and remediation of unsafe conditions, ensuring that certain currently unregulated pipelines are subject to appropriate regulatory oversight, and speeding mitigation of adverse effects of pipeline failures. In addition to safety benefits, the rule is expected to improve the performance and extend the economic life of critical pipeline infrastructure that transports domestically produced natural gas energy, thus supporting national economic and security energy objectives.

Looking at Risk Beyond HCAs

In addition to the common sense improvements to IM, responses to the ANPRM reinforced the importance of carefully reconsidering the scope of areas covered by IM. While PHMSA's IM program manages risks primarily by focusing oversight on areas with the greatest population density, responses to the ANPRM highlight the imperative of protecting the safety of communities throughout the country in light of a changing landscape of production, consumption, and product movement that merits a refreshed look at the current scope of IM coverage.

In the 2011 Act, Congress required PHMSA to have pipeline operators conduct a records verification to ensure that their records accurately reflect the physical and operational characteristics of pipelines in certain HCAs and class locations, and to confirm the established MAOP of the pipelines. The results of that action indicate that problems similar to the contributing factors of the San Bruno incident are more widespread than previously believed, affecting both HCA and non-HCA segments. This indicates that a rupture on the scale of San Bruno, with the potential to affect populations, the environment, or commerce, could occur elsewhere on the nation's pipeline system.

In fact, devastating incidents have occurred outside of HCAs in rural areas where populations are sparse but present. On August 19, 2000, a 30-inch-diameter gas transmission pipeline ruptured adjacent to the Pecos River near Carlsbad, NM. The released gas ignited and burned for 55 minutes. Twelve persons who were camping under a concrete-decked steel bridge that supported the pipeline across the river were killed, and their vehicles were destroyed. Two nearby steel suspension bridges for gas pipelines crossing the river were damaged extensively.

On December 14, 2007, two men were driving in a pickup truck on Interstate 20 near Delhi, LA, when a 30-inch gas transmission pipeline ruptured. One of the men was killed, and the other was injured.

On December 11, 2012, a 20-inch-diameter gas transmission line ruptured in a sparsely populated area about 106 feet west of Interstate 77 (I–77) in Sissonville, WV. An area of fire damage about 820 feet wide extended nearly 1,100 feet along the pipeline right-of-way. Three houses were destroyed by the fire, and several other houses were damaged. Reported losses, repairs, and upgrades from this incident totaled over $8.5 million, and major transportation delays occurred. I–77 was closed in both directions because of the fire and resulting damage to the road surface. The northbound lanes were closed for about 14 hours, and the southbound lanes were closed for about 19 hours while the road was resurfaced, causing delays to both travelers and commercial shipping.

Because the nation's population is growing, moving, and dispersing, population density is a changing measure, and we need to be prepared for further shifts in the coming decades. The current definition of an HCA uses building density as a proxy for approximating the presence of communities and surrounding infrastructure. This can be a meaningful metric for prioritizing implementation of safety and risk management protocols for areas where an accident would have the greatest likelihood of putting human life in danger, but it is not necessarily an accurate reflection of whether an incident will have a significant impact on people. Requiring assessment and repair criteria for pipelines that, if ruptured, could pose a threat to areas where any people live, work, or congregate would improve public safety and would improve public confidence in the nation's natural gas pipeline system.

Feedback from industry indicated that some pipeline operators are already moving towards expanding the protections of IM beyond HCAs. In 2012, the Interstate Natural Gas Association of America (INGAA) issued a ''Commitment to Pipeline Safety,'' [33] underscoring its efforts towards a goal of zero incidents, a committed safety culture, a pursuit of constant improvement, and applying IM principles on a system-wide basis. INGAA divides the commitment into four stages:

- Stage 1—INGAA members will complete an initial assessment using some degree of IM on their pipelines, covering 90% of the population living, working, or congregating along INGAA member pipelines, by the end of 2012. This represents roughly 64% of INGAA member pipeline mileage, including the 4% of pipelines that are in HCAs.
- Stage 2—By 2020, INGAA members will consistently and comprehensively apply IM principles to those pipelines.
- Stage 3—By 2030, INGAA members will apply IM principles to pipelines, extending IM protection to 100% of the population living along INGAA member pipelines. This stage would cover roughly 16% of pipeline mileage, bringing the total coverage by 2030 to approximately 80% of INGAA's pipeline mileage.
- Stage 4—Beyond 2030, INGAA members will apply IM principles to the remaining 20% of pipeline mileage where no population resides.

To accomplish this commitment, INGAA's members are performing actions that include applying risk management beyond HCAs; raising the standards for corrosion management; demonstrating ''fitness for service'' on pre-regulation pipelines; and evaluating, refining, and improving operators' ability to assess and mitigate safety threats. Ultimately, these actions aim to extend protection to people who live near pipelines but not within defined HCAs.

INGAA's commitment and other stakeholder feedback on this issue have triggered an important exchange about measuring the risks that exist in less-densely populated areas and the impacts of expanding greater protections to those areas. If constant improvement and zero incidents are goals for pipeline operators, INGAA's plan to extend and prioritize IM assessments and principles to all parts of their pipeline networks that are located near any concentrations of population is an effective way to achieve those goals. Such an approach is needed to help clarify vulnerabilities and prioritize improvements, and this proposed rulemaking takes important steps forward towards developing such an approach.

[33] Letter from Terry D. Boss, Senior Vice President of Environment, Safety and Operations to Mike Israni, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, dated January 20, 2012, ''*Safety of Gas Transmission Pipelines,* Docket No. PHMSA–2011–0023.'' INGAA represents companies that operate approximately 65 percent of the gas transmission pipelines, but INGAA does not represent all pipeline operators subject to 49 CFR part 192.

The question then, is how to implement risk management standards that most accurately target the safety of communities, while also providing sufficient ability to prioritize areas of greatest possible risk and/or impact. Addressing that question has been, and remains, an important part of this proposed rule, recognizing that the answer will remain fluid based on factors that continue to change.

Given INGAA's commitment, feedback from the ANPRM, the results of incident investigations, and IM considerations, PHMSA has determined it is appropriate to improve aspects of the current IM program and codify requirements for additional gas transmission pipelines to receive integrity assessments on a periodic basis to monitor for, detect, and remediate pipeline defects and anomalies. In addition, in order to achieve the desired outcome of performing assessments in areas where people live, work, or congregate, while minimizing the cost of identifying such locations, PHMSA proposes to base the requirements for identifying those locations on processes already being implemented by pipeline operators and that protect people on a risk-prioritized basis.

Establishing integrity assessment requirements and associated repair conditions for non-HCA pipe segments is important for providing safety to the public. Although those segments are not within defined HCAs, they will usually be located in populated areas, and pipeline accidents in these areas may cause fatalities, significant property damage, or disrupt livelihoods. This rulemaking proposes a newly defined moderate consequence area (MCA) to identify additional non-HCA pipeline segments that would require integrity assessments, thus assuring timely discovery and repair of pipeline defects in MCA segments. These changes would ensure prompt remediation of anomalous conditions that could potentially impact people, property, or the environment, and commensurate with the severity of the defects, while at the same time allowing operators to allocate their resources to HCAs on a higher-priority basis. INGAA's commitment and PHMSA's MCA definition are comparable, which shows a common understanding of the importance of this issue and a path towards a solution.

B. Advance Notice of Proposed Rulemaking

On August 25, 2011, PHMSA published an Advance Notice of Proposed Rulemaking (ANPRM) to seek public comments regarding the revision of the Pipeline Safety Regulations applicable to the safety of gas transmission pipelines. In particular, PHMSA requested comments regarding whether integrity management (IM) requirements should be changed and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. The ANPRM may be viewed at *http://www.regulations.gov* by searching for Docket ID PHMSA–2011–0023. As mentioned above, pursuant to the related issues raised by the NTSB recommendations and statutory requirements of the Act, PHMSA is issuing separate rulemaking for several of the topics in the ANPRM. These topics are so designated in the following list. Specifically, the ANPRM sought comments on the following topics:

A. Modifying the Definition of HCA (to be addressed in separate rulemaking),

B. Strengthening Requirements to Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs (partially addressed in separate rulemaking—aspects related to Remote Control Valves and Leak Detection will be addressed in separate rulemaking, other aspects are being addressed in this NPRM),

C. Modifying Repair Criteria,

D. Improving Requirements for Collecting, Validating, and Integrating Pipeline Data,

E. Making Requirements Related to the Nature and Application of Risk Models More Prescriptive,

F. Strengthening Requirements for Applying Knowledge Gained Through the IM Program,

G. Strengthening Requirements on the Selection and Use of Assessment Methods,

H. Valve Spacing and the Need for Remotely or Automatically Controlled Valves (to be addressed in separate rulemaking),

I. Corrosion Control,

J. Pipe Manufactured Using Longitudinal Weld Seams,

K. Establishing Requirements Applicable to Underground Gas Storage (to be considered for separate rulemaking),

L. Management of Change,

M. Quality Management Systems (QMS) (to be considered for separate rulemaking),

N. Exemption of Facilities Installed Prior to the Regulations,

O. Modifying the Regulation of Gas Gathering Lines.

A summary of comments and responses to those comments are provided later in the document.

C. National Transportation Safety Board Recommendations

On August 30, 2011, following the issuance of the ANPRM, the NTSB adopted its report on the gas pipeline accident that occurred on September 9, 2010, in San Bruno, California. On September 26, 2011, the NTSB issued safety recommendations P–11–8 through –20 to PHMSA, and issued safety recommendations P–10–2 through –4 to Pacific Gas & Electric (PG&E), among others. The NTSB made these recommendations following its investigation of the tragic September 9, 2010 natural gas pipeline rupture in the city of San Bruno, California. Several of the NTSB recommendations related directly to the topics addressed in the August 25, 2011 ANPRM and impacted the proposed approach to rulemaking. The potentially impacted topics and the related NTSB recommendations include, but are not limited to:

- Topic B—Strengthening Requirements to Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs. NTSB Recommendation P–11–10: ''*Require that all operators of natural gas transmission and distribution pipelines equip their supervisory control and data acquisition systems with tools to assist in recognizing and pinpointing the location of leaks, including line breaks; such tools could include a real-time leak detection system and appropriately spaced flow and pressure transmitters along covered transmission lines.*''
- Topic D—Improving Requirements for Collecting, Validating, and Integrating Pipeline Data. NTSB Recommendation P–11–19: ''*(1) Develop and implement standards for integrity management and other performance-based safety programs that require operators of all types of pipeline systems to regularly assess the effectiveness of their programs using clear and meaningful metrics, and to identify and then correct deficiencies; and (2) make those metrics available in a centralized database.*''
- Topic G—Strengthening Requirements on the Selection and Use of Assessment Methods. NTSB Recommendation P–11–17: ''*Require that all natural gas transmission pipelines be configured so as to accommodate in-line inspection tools, with priority given to older pipelines.*''
- Topic H—Valve Spacing and the Need for Remotely or Automatically Controlled Valves. NTSB Recommendation P–11–11: ''*Amend Title 49 Code of Federal Regulations Section 192.935(c) to directly require that automatic shutoff valves or remote*

control valves in high consequence areas and in class 3 and 4 locations be installed and spaced at intervals that consider the population factors listed in the regulations.''

• Topic J—Pipe Manufactured Using Longitudinal Weld Seams. NTSB Recommendation P–11–15: ''*Amend Title 49 Code of Federal Regulations Part 192 of the Federal pipeline safety regulations so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure.*''

• Topic N—Exemption of Facilities Installed Prior to the Regulations. NTSB Recommendation P–11–14: *Amend title 49 Code of Federal Regulations 192.619 to repeal exemptions from pressure test requirements and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.*''

D. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

Also subsequent to issuance of the ANPRM, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act) was enacted on January 3, 2012. Several of the Act's statutory requirements relate directly to the topics addressed in the August 25, 2011 ANPRM. The related topics and statutory citations include, but are not limited to:

○ Section 5(e)—Allow periodic reassessments to be extended for an additional 6 months if the operator submits sufficient justification.

○ Section 5(f)—Requires regulations issued by the Secretary, if any, to expand integrity management system requirements, or elements thereof, beyond high-consequence areas.

○ Section 21—Regulation of Gas (and Hazardous Liquid) Gathering Lines

○ Section 23—Testing regulations to confirm the material strength of previously untested natural gas transmission pipelines.

○ Section 29—Consider seismicity when evaluating pipeline threats.

E. Summary of Each Topic Under Consideration

This NPRM proposes new requirements and revisions to existing requirements to address topics discussed in the ANPRM, including some topics from the Act and the NTSB recommendations. Each topic area discussed in the ANPRM, as well as additional topics that have arisen since issuance of the ANPRM, is summarized below. Details of the changes proposed in this rule are discussed below in section V. Section-by-Section Analysis.

• Topic A—Modifying the Definition of HCA. The ANPRM requested comments regarding expanding the definition of an HCA so that more miles of pipe would be subject to IM requirements and so that all Class 3 and 4 locations would be subject to the IM requirements. The Act, Section 5, requires that the Secretary of Transportation complete an evaluation and issue a report on whether integrity management requirements should be expanded beyond HCAs and whether such expansion would mitigate the need for class location requirements. PHMSA has prepared the class location report and a copy is available in the docket (*www.regulations.gov*) for this proposed rulemaking. PHMSA invites commenters to review the class location report when formulating their comments.

Although PHMSA is not proposing to expand the definition of an HCA, PHMSA is proposing to expand certain IM requirements beyond HCAs by creating a new ''moderate consequence areas (MCA).'' MCAs would be used to define the subset of non-HCA pipeline locations where periodic integrity assessments are required (§ 192.710), where material documentation verification is required (§ 192.607), and where MAOP verification is required (§§ 192.619(e) and 192.624). The proposed criteria for determining MCA locations would use the same process and the same definitions as currently used to identify HCAs, except that the threshold for buildings intended for human occupancy and the threshold for persons that occupy other defined sites, that are located within the potential impact radius, would both be lowered from 20 to 5. The intention is that any pipeline location at which persons are normally expected to be located would be afforded extra safety protections described above. In addition, as a result of the Sissonville, West Virginia incident, NTSB issued recommendation P–14–01, to revise the gas regulations to add principal arterial roadways including interstates, other freeways and expressways, and other principal arterial roadways as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures* to the list of ''identified sites'' that establish a high consequence area. PHMSA proposes to meet the intent of NTSB's recommendation by incorporating designated interstates, freeways, expressways, and other principal 4-lane arterial roadways (as opposed to NTSB's all ''other principal arterial roadways'') within the new definition of MCAs. PHMSA believes this approach would be cost-beneficial. The Sissonville, WV, incident location would not meet the current definition of an HCA, but would, however, meet the proposed definition of an MCA. PHMSA considered expanding the scope of HCAs instead of creating Moderate Consequence Areas. Such an approach was contemplated in the 2011 ANPRM and PHMSA received a number of comments on this approach. PHMSA concluded that this approach would be counter to a graded approach based on risk (*i.e.,* risk based gradation of requirements to apply progressively more protection for progressively greater consequence locations). By simply expanding HCAs, PHMSA would be simply lowering the threshold for what is considered ''high consequence.'' Expanding HCAs would require that all integrity management program elements (specified in subpart O) be applied to pipe located in a newly designated HCA. The proposed rule would only apply three IM program elements (assessment, periodic reassessment, and remediation of discovered defects) to the category of pipe that has lesser consequences than HCAs (*i.e.,* MCAs), but not to segments without any structure or site within the PIR (arguably ''low consequence areas''). There would be additional significant costs to apply all other integrity management program elements (most notably the risk analysis and preventive/mitigative measures program elements) to additional segments currently not designated as HCA. Also, if HCAs were expanded, long term reassessment costs would approximately triple (compared to the proposed MCA requirements) based on an almost 3:1 ratio of reassessment interval. For the above reasons, PHMSA is not proposing to expand HCAs. Instead, PHMSA is proposing to create and apply selected integrity management requirements to a category of lesser consequence areas defined as MCAs. With regard to the criteria for defining HCAs, PHMSA also considered several alternatives, including more relaxed population density and excluding small pipe diameters.

In addition, a major constituency of the pipeline industry (INGAA) has committed to apply IM principles to all segments where any persons are located. This is comparable to PHMSA's proposed MCA definition. PHMSA seeks comment on the relative merits of expanding High Consequence Areas

versus creating a new category of ''Moderate Consequence Areas.''

Another alternative PHMSA considered was a shorter a compliance deadline (10 years) and a shorter reassessment interval (15 years) for MCA assessments. The assessment timeframes in the proposed rule were selected based on a graded approach which would apply relaxed timeframes to MCAs, as compared to HCAs. The industry was originally required to perform baseline assessments for approximately 20,000 miles of HCA pipe within approximately 8 years from the effective date of the integrity management rule. PHMSA estimates that approximately 41,000 miles of pipe would require an assessment within 15 years under this proposed rule, thus constituting a comparable level of effort on the part of industry. The maximum HCA reassessment interval is 20 years for low stress pipe. The 20 year interval was selected to align with the longest interval allowed for any HCA pipe, which is 20 years for pipe operating less than 30% SMYS. A reassessment interval of 15 years for MCAs would be shorter than the reassessment interval for some HCAs. PHMSA also considered that compliance with the proposed rule would be performed in parallel with ongoing HCA reassessments at the same time, thus resulting in greater demand for ILI tools and industry resources than during the original IM baseline assessment period. In addition, the proposed rule incorporates other assessment goals, including integrity verification, maximum allowable operating pressure (MAOP) verification, and material documentation, thus constituting a larger/more costly assessment effort than originally required under IM rules. For the above reasons, PHMSA believes that this proposed rule would require full utilization or expansion of industry resources devoted to assessments. Therefore, PHMSA believes that compressing the timeframes would place unreasonably high demands on the industry's assessment capabilities. PHMSA also considered the possibility that placing burdensome demands on the industry's assessment capability might drive assessment costs higher. PHMSA seeks comments on the potential safety benefits, avoided lost gas, economic costs, and operational considerations involved in longer or shorter compliance periods for initial MCA assessment periods and re-assessment intervals.

More generally, PHMSA seeks comment on the approach and scope of the proposed rule with respect to applying integrity management program elements to additional pipe segments not currently designated as HCA, including, *inter alia,* alternative definitions of ''Moderate Consequence Area'' and limits on the categories of pipeline to be regulated within this new area.

• Topic B—Strengthening Requirements to Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs. The ANPRM requested comments regarding whether the requirements of Section 49 CFR 192.935 for pipelines in HCAs should be more prescriptive and whether these requirements, or other requirements for additional preventive and mitigative measures, should apply to pipelines outside of HCAs. Section 5 of the Act requires the Secretary of Transportation to evaluate and report to Congress on expanding IM requirements to non-HCA pipelines. PHMSA will further evaluate applying P&M measures to non-HCA areas after this evaluation is complete.

This NPRM proposes rulemaking for amending the integrity management rule to add requirements for selected preventive and mitigative measures (internal and external corrosion control).

Two special topics associated with preventive and mitigative measures, leak detection and automatic valve upgrades, were addressed by the NTSB and Congress. The NTSB recommended that all operators of natural gas transmission and distribution pipelines equip their supervisory control and data acquisition systems with tools to assist in recognizing and pinpointing the location of leaks, including line breaks; such tools could include a real-time leak detection system and appropriately spaced flow and pressure transmitters along covered transmission lines (recommendation P–11–10). In addition, Section 8 of the Act requires issuance of a report on leak detection systems used by operators of hazardous liquid pipelines which was completed and submitted to Congress in December 2012. Although that study is specific to hazardous liquid pipelines, its analysis and conclusions could influence PHMSA's approach to leak detection for gas pipelines. In response to the NTSB recommendations, PHMSA conducted as part of a larger study on pipeline leak detection technology a public workshop in 2012. This study, among other things, examined how enhancements to SCADA systems can improve recognition of pipeline leak locations. Additionally, in 2012 PHMSA held a pipeline research forum to identify technological gaps, potentially including the advancement of leak detection methodologies. PHMSA is developing a rulemaking with respect to leak detection in consideration of these studies and ongoing research. In addition, PHMSA is focusing this rulemaking on regulations oriented toward preventing incidents. Leak detection (in the context of mitigating pipe breaks as described in NTSB P–11–10) [34] and automatic valve upgrades are features that serve to mitigate the consequences of incidents after they occur but do not prevent them. In order to not delay the important requirements proposed in this NPRM, PHMSA will address the topic of incident mitigation later in a separate rulemaking. It is anticipated that advancing rulemaking to address the NTSB recommendations will follow assessment of the results of these actions.

PHMSA completed and submitted the valve study to congress in December 2012. PHMSA is developing a separate rulemaking related to the need for remotely or automatically controlled valves to addresses the NTSB recommendations and statutory requirements related to this topic as discussed under Topic H.

• Topic C—Modifying Repair Criteria. The ANPRM requested comments regarding amending the integrity management regulations by revising the repair criteria for pipelines in HCAs to provide greater assurance that injurious anomalies and defects are repaired before the defect can grow to a size that leads to a leak or rupture. PHMSA is proposing in this rule to revise the repair criteria for pipelines in HCAs. Revisions include repair criteria for cracks and crack-like defects, corrosion metal loss for defects less severe than an immediate condition (already included), and mechanical damage defects.

In addition, the ANPRM requested comments regarding establishing repair criteria for pipeline segments located in areas that are not in HCAs. PHMSA is proposing rulemaking for establishing repair criteria for pipelines that are not in HCAs. Such repair criteria would be similar to the repair criteria for HCAs, with more relaxed deadlines for non-immediate conditions. It is acknowledged that applying repair criteria to pipelines that are not in HCAs is one of the factors to be considered in the integrity management evaluation required in the Act, as discussed in Topic A above.

• Topic D—Improving Requirements for Collecting, Validating, and Integrating Pipeline Data. The ANPRM

[34] Leak detection in the context of detecting small, latent leaks such as leaks at fittings typical of gas distribution systems, and is outside the scope of the ANPRM, Topic B.

requested comments regarding whether more prescriptive requirements for collecting, validating, integrating, and reporting pipeline data are necessary. PHMSA also discussed this topic in a 2012 pipeline safety data workshop.

PHMSA issued Advisory Bulletin 12–06 to remind operators of gas pipeline facilities to verify their records relating to operating specifications for maximum allowable operating pressure (MAOP) required by 49 CFR 192.517. On January 10, 2011, PHMSA also issued Advisory Bulletin 11–01, which reminded operators that if they are relying on the review of design, construction, inspection, testing and other related data to establish MAOP, they must ensure that the records used are reliable, traceable, verifiable, and complete. PHMSA is proposing in this rule to add specificity to the data integration language in the IM rule to establish a number of pipeline attributes that must be included in these analyses, by explicitly requiring that operators integrate analyzed information, and by requiring that data be verified and validated. In addition, PHMSA has determined that additional rules are needed to ensure that records used to establish MAOP are reliable, traceable, verifiable, and complete. The proposed rule would add a new paragraph (e) to section 192.619 to codify this requirement and to require that such records be retained for the life of the pipeline.

• Topic E—Making Requirements Related to the Nature and Application of Risk Models More Detailed. The ANPRM requested comments regarding making requirements related to the nature and application of risk models more specific to improve the usefulness of these analyses in informing decisions to control risks from pipelines. This NPRM contains proposed requirements that address this topic.

• Topic F—Strengthening Requirements for Applying Knowledge Gained Through the IM Program. The ANPRM requested comments regarding strengthening requirements related to operators' use of insights gained from implementation of its IM program. In this NPRM, PHMSA proposes detailed requirements for strengthening integrity management requirements for applying knowledge gained through the IM Program. These requirements include provisions for analyzing interacting threats, potential failures, and worst-case incident scenarios from initial failure to incident termination. Though not proposed, PHMSA seeks comment on whether a time period for updating aerial photography and patrol information should be established.

• Topic G—Strengthening Requirements on the Selection and Use of Assessment Methods for pipelines requiring assessment. The ANPRM requested comments regarding the applicability, selection, and use of assessment methods, including the application of existing consensus standards. NTSB recommendation P–11–17 related to this topic, recommends that all gas pipelines be upgraded to accommodate ILI tools. PHMSA will consider separate rulemaking for upgrading pipelines pending further evaluation of the issue from new data being collected in the annual reports.

This NPRM proposes to strengthen requirements for the selection and use of assessment methods. The proposed rule would provide more detailed guidance for the selection of assessment methods, including the requirements in new § 192.493 when performing an assessment using an in-line inspection tool. This NPRM also proposes to add more specific requirements for use of internal inspection tools to require that an operator using this method must explicitly consider uncertainties in reported results when identifying anomalies. In addition, the proposed rulemaking would add a ''spike'' hydrostatic pressure test, which is particularly well suited to address SCC and other cracking or crack-like defects, guided wave ultrasonic testing (GWUT), which is particularly appropriate in cases where short segments, such as roads or railroad crossings, are difficult to assess, and excavation and *in situ* direct examination, which is well suited to address crossovers and other short, easily accessible segments that are impractical to assess by remote technology, as allowed assessment methods and would revise the requirements for direct assessment to allow its use only if a line is not capable of inspection by internal inspection tools.

The issue of selection and use of assessment methods is related to the statutory mandate in the Act for the Comptroller General of the United States to evaluate whether risk-based reassessment intervals are a more effective alternative. The Act requires an evaluation of reassessment intervals and the anomalies found in reassessments. While not directly addressing selection of assessment methods, the results of the evaluation will have an influence on the general approach for conducting future integrity assessments. PHMSA will consider the Comptroller General's evaluation when it becomes available. Additional rulemaking may be considered after PHMSA considers the results of the evaluation.

• Topic H—Valve Spacing and the Need for Remotely or Automatically Controlled Valves. The ANPRM requested comments regarding proposed changes to the requirements for sectionalizing block valves. In response to the NTSB recommendations, PHMSA held a public workshop in 2012 on pipeline valve issues, which included the need for additional valve installation on both natural gas and hazardous liquid transmission pipelines. PHMSA also included this topic in the 2012 Pipeline Research Forum. In addition, Section 4 of the Act requires issuance of regulations on the use of automatic or remote-controlled shut-off valves, or equivalent technology, where economically, technically, and operationally feasible on transmission pipeline facilities constructed or entirely replaced after the date of the final rule. The Act also requires completion of a study by the Comptroller General of the United States on the ability of transmission pipeline facility operators to respond to a hazardous liquid or gas release from a pipeline segment located in an HCA. Separate rulemaking on this topic will be considered based on the results of the study.

• Topic I—Corrosion Control. The ANPRM requested comments regarding proposed revisions to subpart I to improve the specificity of existing requirements. This NPRM proposes to revise subpart I, including a general update to the technical requirements in appendix D to part 192 for cathodic protection.

• Topic J—Pipe Manufactured Using Longitudinal Weld Seams. In recommendation P–11–15, the NTSB recommended that PHMSA amend its regulations to require that any longitudinal seam in an HCA be pressure tested in order to consider the seam to be ''stable.'' This issue is addressed in Topic N. PHMSA proposes to address this issue by revising the integrity management requirements in § 192.917(e)(3) to specify that longitudinal seams may not be treated as stable defects unless the segment has been pressure tested (and therefore would require an integrity assessment for seam threats). Also, PHMSA proposes to add new requirements for verification of maximum allowable operating pressure (MAOP) in new § 192.624.

• Topic K—Establishing Requirements Applicable to Underground Gas Storage. The ANPRM requested comments regarding establishing requirements within part 192 applicable to underground gas storage in order to help assure safety of

underground storage and to provide a firm basis for safety regulation. PHMSA will consider proposing a separate rulemaking that specifically focuses on improving the safety of underground natural gas storage facilities will allow PHMSA to fully consider the impacts of incidents that have occurred since the close of the initial comment period. It will also allow the Agency to consider voluntary consensus standards that were developed after the close of the comment period for this ANPRM, and to solicit feedback from additional stakeholders and members of the public to inform the development of potential regulations.

• Topic L—Management of Change. The ANPRM requested comments regarding adding requirements for management of change to provide a greater degree of control over this element of pipeline risk. This NPRM contains proposed requirements that address this topic. Specifically, PHMSA proposes to revise the general applicability requirements in § 192.13 to require each operator of an onshore gas transmission pipeline to develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary.

• Topic M—Quality Management Systems (QMS). The ANPRM requested comments regarding whether and how to impose requirements related to quality management systems. PHMSA will consider separate rulemaking for this topic.

• Topic N—Exemption of Facilities Installed Prior to the Regulations. The ANPRM requested comments regarding proposed changes to part 192 regulations that would repeal exemptions to pressure test requirements. The NTSB recommended that PHMSA repeal 49 CFR 192.619(c) and require that all gas transmission pipelines be pressure tested to establish MAOP (recommendation P–11–14). In addition, section 23 of the Act requires issuance of regulations requiring tests to confirm the material strength of previously untested natural gas transmission lines. In response to the NTSB recommendation and the Act, this NPRM proposes requirements for verification of maximum allowable operating pressure (MAOP) in accordance with new § 192.624 for certain onshore, steel, gas transmission pipelines, including establishing and documenting MAOP if the pipeline MAOP was established in accordance with § 192.619(c).

The Act also requires verification of records to ensure they accurately reflect the physical and operational characteristics of the pipelines and to confirm the established maximum allowable operating pressure of the pipelines. PHMSA issued Advisory Bulletin 12–06 on May 7, 2012 to notify operators of this required action. PHMSA has initiated an information collection effort to gather data needed to accurately characterize the quantity and location of pre-1970 gas transmission pipeline operating under an MAOP established by 49 CFR 192.619(c). This NPRM proposes requirements in new § 192.607 for certain onshore, steel, gas transmission pipelines to confirm and record the physical and operational characteristics of pipelines for which adequate records are not available.

• Topic O—Modifying the Regulation of Gas Gathering Lines. The ANPRM requested comments regarding modifying the regulations relative to gas gathering lines. The Act required several actions related to this topic, including: review existing regulations for gathering lines; provide a report to Congress; and make recommendations on: (1) The sufficiency of existing regulations, (2) the economic impacts, technical practicability, and challenges of applying existing federal regulations to gathering lines, and (3) subject to a risk-based assessment, the need to modify or revoke existing exemptions from Federal regulation for gas and hazardous liquid gathering lines. PHMSA proposes to address aspects of this topic identified before enactment of the Act in this NPRM. The report submitted to Congress will be evaluated to determine the need for any future rulemaking, specifically the need to apply integrity management concepts to gas gathering lines.

In addition, on August 20, 2014, the Government Accountability Office (GAO) released a report (GAO Report 14–667) to address the increased risk posed by new gathering pipeline construction in shale development areas. The GAO recommended that rulemaking be pursued for gathering pipeline safety that addresses the risks of larger-diameter, higher-pressure gathering pipelines, including subjecting such pipelines to emergency response planning requirements that currently do not apply. PHMSA proposes to address this recommendation as described below in the ''Section-by-Section Analysis'' under § 192.9.

Additional Topics

• Inspection of Pipelines Following a Severe Weather Event. Existing pipeline regulations prescribe requirements for surveillance periodically patrolling of pipeline to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation, including unusual operating and maintenance conditions. The cause of the 2011 hazardous liquid pipeline accident resulting in a crude oil spill into the Yellowstone River near Laurel, Montana was scouring at the river crossing due to flooding. In this case, annual heavy flooding occurred in the Spring of the 2011. In late May, the operator shut down the pipeline for several hours to assess the state of the pipeline. Following the assessment, the operator restarted the pipeline and agreed to monitor the river area on a daily basis. On July 1, 2011 the pipeline ruptured which resulted in the release of 1,500 barrels of crude oil into the Yellowstone River. A second break, due to exposure to flood conditions, occurred several years later on the same pipeline led to an additional spill in the Yellowstone River. Other examples include Hurricane Katrina (2005) which resulted in significant damage to the oil and gas production structures and the San Jacinto flood (1994) which resulted in 8 ruptures and undermining of 29 other pipelines. In the context of the San Jacinto flood, ''undermining'' occurred when support material for the pipelines was removed due to erosion driven by the floodwaters. As a result, the unsupported pipelines were subjected to stress from the floodwaters that resulted in fatigue cracks in the pipe walls. Based on these examples of extreme weather events that did result, or could have resulted, in pipeline incidents, PHMSA has determined that additional regulations are needed to require, and establish standards for, inspection of the pipeline and right-of-way for ''other factors affecting safety and operation'' following an extreme weather event, such as a hurricane or flood, an earthquake, a natural disaster, or other similar event that has the likelihood of damage to infrastructure. The proposed rule would require such inspections, specify the timeframe in which such inspections should commence, and specify the appropriate remedial actions that must be taken to ensure safe pipeline operations. The new regulation would apply to onshore transmission pipelines and their rights-of-way.

• Notification for 7-Year Reassessment Interval Extension. Subsection 5(e) of the Act identifies a technical correction amending section 60109(c)(3)(B) of title 49 of the United States Code to allow the Secretary of Transportation to extend the 7- calendar year reassessment interval for an additional 6 months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension. PHMSA would expect that any justification, at a minimum, would need to demonstrate that the extension does not pose a safety risk. PHMSA proposes to codify this statutory requirement.

• Reporting Exceedances of Maximum Allowable Operating Pressure. Section 23 of the Act requires operators to report to PHMSA each exceedance of the maximum allowable operating pressure (MAOP) that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. Implicit in § 192.605 is the intent for operators to establish operational and maintenance controls and procedures to effectively preclude operation at pressures that exceed MAOP. PHMSA expects that operators' procedures should already address this aspect of operations and maintenance, as it is a long-standing, critical aspect of safe pipeline operations. PHMSA issued ADB 12–11 to address exceedances of MAOP. However, PHMSA proposes to codify this statutory requirement in § 192.605.

• Consideration of Seismicity. Section 29 of the Act states that in identifying and evaluating all potential threats to each pipeline segment, an operator of a pipeline facility must consider the seismicity of the area. PHMSA proposes to codify this statutory requirement by adding requirements to explicitly reference seismicity for data gathering and integration, threat identification, and implementation of preventive and mitigative measures.

• Safety Regulations for In-line Inspection (ILI), Scraper, and Sphere Facilities. PHMSA is proposing to add explicit requirements for safety features on launchers and receivers associated with ILI, scraper and sphere facilities.

• Consensus Standards for Pipeline Assessments. The proposed rule would incorporate by reference industry standards for assessing the physical condition of in-service pipelines using in-line inspection, internal corrosion direct assessment, and stress corrosion cracking direct assessment. Periodic assessment of the condition of gas transmission pipelines in HCAs is required by 49 CFR 192.921 and 192.937. The regulations provide minimal requirements for the use of these assessment techniques since at the time these regulations were established, industry standards did not exist addressing how these techniques should be applied. Incorporation of standards subsequently published by the American Petroleum Institute (API), the National Association of Corrosion Engineers (NACE), and the American Society of Nondestructive Testing (ASNT) would assure better consistency, accuracy and quality in pipeline assessments conducted using these techniques.

F. Integrity Verification Process Workshop

An Integrity Verification Process (IVP) workshop was held on August 7, 2013. At the workshop, PHMSA, the National Association of State Pipeline Safety Representatives and various other stakeholders presented information and comments were sought on a proposed IVP that will help address mandates set forth in Section 23, Maximum Allowable Operating Pressure, of the Act and the NTSB Recommendations P–11–14 (repeal pressure test exemptions) and P–11–15 (stability of manufacturing and construction defects). Key aspects of the proposed IVP process include criteria for establishing which pipe segments would be subject to the IVP, technical requirements for verifying material properties where adequate records are not available, and technical requirements for re-establishing MAOP where adequate records are not available or the existing MAOP was established under § 192.619(c). Comments were received from the American Gas Association, the Interstate Natural Gas Association of America, and other stakeholders addressing the draft IVP flow chart, technical concerns for implementing the proposed IVP, and other issues. The detailed comments are available under Docket No. PHMSA–2013–0119. PHMSA considered and incorporated the stakeholder input, as appropriate, into this NPRM, which proposes requirements to address the current exemptions to pressure test requirements, manufacturing and construction defect stability, verification of MAOP where records to establish MAOP are not available or inadequate (new §§ 192.619(e) and 192.624), and verification and documentation of pipeline material for certain onshore, steel, gas transmission pipelines (new § 192.607).

III. Analysis of Comments on the ANPRM

In Section II of the ANPRM, PHMSA sought comments concerning the significance of the proposed issues to pipeline safety; whether new/revised regulations are needed and, if so, suggestions as to what changes are needed; and likely costs that would be associated with implementing any new/revised requirements. PHMSA posed specific questions to solicit stakeholder input. These included questions related to 15 specific topic areas in two broad categories:

1. Should IM requirements be revised and strengthened to bring more pipeline mileage under IM requirements and to better assure safety of pipeline segments in HCAs? Specific topics included:

A. Modifying the Definition of HCA,

B. Strengthening Requirements to Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs,

C. Modifying Repair Criteria,

D. Improving Requirements for Collecting, Validating, and Integrating Pipeline Data,

E. Making Requirements Related to the Nature and Application of Risk Models More Prescriptive,

F. Strengthening Requirements for Applying Knowledge Gained Through the IM Program,

G. Strengthening Requirements on the Selection and Use of Assessment Methods.

2. Should non-IM requirements be strengthened or expanded to address other issues associated with pipeline system integrity. Specific topics included:

H. Valve Spacing and the Need for Remotely or Automatically Controlled Valves,

I. Corrosion Control,

J. Pipe Manufactured Using Longitudinal Weld Seams,

K. Establishing Requirements Applicable to Underground Gas Storage,

L. Management of Change,

M. Quality Management Systems (QMS),

N. Exemption of Facilities Installed Prior to the Regulations,

O. Modifying the Regulation of Gas Gathering Lines.

PHMSA received a total of 1,463 comments; 1,080 from industry sources (Trade Associations/Unions, Pipeline Operators and Consultants); 316 comments from the public (Environmental Groups, Government Agencies/Municipalities, NAPSR and individual members of the general public); and 67 general comments not directly related to the ANPRM questions or categories. Commenters included:

- Citizen Groups
  - Environmental Defense Fund (EDF)
  - League of Women Voters of Pennsylvania (LWV)
  - Pipeline Safety Trust (PST)
  - State of Washington Citizens Advisory Committee on Pipeline Safety (CCOPS)
- Consultants
  - Accufacts Inc.
  - Oleksa and Associates, Inc.
  - Thomas M. Lael
  - WKM Consultancy, LLC
- Government Agencies
  - California Public Utilities Commission (CPUC)
  - City and County of San Francisco (CCSF)
  - Federal Energy Regulatory Commission (FERC)
  - Harris County Fire Marshal's Office (HCFM)
  - Interstate Oil and Gas Compact Commission (IOGCC)
  - Iowa Utilities Board
  - Kansas Corporation Commission (KCC)
  - Kansas Department of Health and Environment (KDHE)
  - National Association of Pipeline Safety Representatives (NAPSR)
  - National Transportation Safety Board (NTSB)
  - Railroad Commission of Texas (TRRC)
  - State of Alaska—AK Natural Gas Development Authority (AKN)
  - State of Alaska Dept. of Natural Resources (AKDNR)
  - Wyoming County Commissioners of Pennsylvania (WYCTY)
- Pipeline Industry
  - Air Products and Chemicals, Inc.
  - Alliance Pipeline
  - Ameren Illinois (AmerenIL)
  - Atmos Energy
  - Avista Corporation
  - CenterPoint Energy
  - CenterPoint Energy Resources Corp.
  - Chevron
  - Dominion East Ohio Gas (DEOG)
  - El Paso (EPPG)
  - ITT Exelis Geospatial Systems
  - Kern River Gas Transmission Company
  - MidAmerican Energy Company
  - National Fuel Gas Supply Corporation
  - National Grid
  - Nicor Gas
  - NiSource Gas Transmission & Storage
  - Northern Natural Gas
  - Paiute Pipeline Company
  - Panhandle Energy
  - Questar Gas Company
  - Questar Pipeline Company
  - SCGC and SDG&E (Sempra)
  - Southern Star Central Gas Pipeline, Inc.
  - Southwest Gas Corporation
  - Spectra Energy
  - TransCanada
  - TransCanada Corporation
  - Waste Management, Inc
  - Williams Gas Pipeline
- Municipalities
  - Delaware Solid Waste Authority (DSWA)
  - Iowa Association of Municipal Utilities (IAMU)
- Trade Associations
  - American Gas Association (AGA)
  - American Public Gas Association (APGA)
  - Gas Processors Association (GPA)
  - Gas Piping Technology Committee (GPTC)
  - Independent Petroleum Association of America, its Cooperating Associations, and the American Petroleum Institute (IPAA/API)
  - Interstate Natural Gas Association of America (INGAA)
  - NACE International
  - National Solid Waste Management Association (NSWMA)
  - National Utility Locating Contractors Association (Locators)
  - Oklahoma Independent Petroleum Association (OKIPA)
  - Texas Oil and Gas Association (TXOGA)
  - Texas Pipeline Association (TPA)
- Trade Unions
  - Professional Engineers in California Government (PECG)
- 31 Private Citizens

Commenters responded to ANPRM questions, but also submitted comments on subjects generally related to gas pipeline safety regulation (but not related to an ANPRM topic) and general comments related to a topic but not in response to any specific question. This NPRM presents a summary of the comments received (similar or duplicate comments are consolidated). The general (no-topic) comments are presented first under the heading "General Comments." Comments on each topic follow under the heading "Comments on ANPRM Section II Topics on Which PHMSA Sought Comment," beginning with general comments related to the topic and then proceeding to each individual question.

General Comments

General Industry Comments

1. A number of commenters associated with the pipeline industry suggested that PHMSA should defer action on the changes discussed in the ANPRM until the studies required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 are completed. They contended the Act presents critical issues that require priority attention. They believe the questions raised by Congress, and to which the studies are addressed, could lead to fundamental changes in how pipeline safety is regulated and these changes need to be understood before new rules are written. Several commenters also suggested PHMSA lacks the resources to pursue simultaneously the required studies and complicated rulemakings. The Railroad Commission of Texas also suggested no new requirements be proposed until the effects of the new Act are understood, since they believe that the Act will change the scope of regulatory authority and impose additional costs on industry and regulators.

Response

PHMSA has placed studies and evaluations that relate to the topics in this proposed rulemaking on the docket. PHMSA seeks public comment on those reports and will consider comments before finalizing this rule. Other topics not addressed in this rulemaking that require additional study or evaluation will be addressed separately. Areas for safety improvement that have previously been identified and that are not dependent on the outcome of the required studies are also the subject of the proposals in this Notice.

2. INGAA, AGA, and several pipeline operators and consultants commented that the ANPRM suggested that PHMSA intends to pursue prescriptive regulation in a number of areas. They objected to this approach. They prefer performance-based regulation, under which operators have greater flexibility in deciding how the required safety goal can be met, considering the specific circumstances of their pipeline systems. They noted that integrity management, a performance-based approach, has greatly improved pipeline safety, and suggested PHMSA consider expanding the elements to be covered in an IM plan and providing more well-defined guidelines on how these expanded plans should evolve over time. They noted that implementing pipeline safety regulations is a complex process and implementing prescriptive requirements is usually inefficient. They also noted that prescriptive requirements tend to discourage technological advancements which can lead to improved means to assure safety.

Response

PHMSA believes performance-based regulations are central to improving pipeline performance. In some instances, however, prescriptive

requirements may be necessary to provide the requisite improvement to pipeline safety performance; for example, requirements for corrosion control, repair conditions, and repair criteria to more specifically address significant corrosion issues. In these cases, the unsafe condition can be clearly specified, and steps necessary to remediate the risk are well-understood engineering practice. PHMSA is committed to an efficient and effective approach to pipeline safety, and using prescriptive regulatory requirements only where necessary.

3. AGA, Texas Pipeline Association, Texas Oil and Gas Association, and a number of pipeline operators objected to the scope and pace of change in pipeline safety regulation. These commenters noted that the ANPRM covered a number of complex issues. In addition, they noted that pipeline operators are still implementing a number of large new initiatives including control room management, public awareness, distribution integrity management, and damage prevention. They commented that the industry needs time to complete implementing these other new regulations and PHMSA and the industry need time to evaluate the effect they have on pipeline safety. AGA specifically expressed concern that the pace of change could result in unintended adverse consequences. The Texas Associations suggested that any expansion of non-HCA regulations should address highest risks first and be structured to tailor requirements to different pipeline conditions because other approaches are likely to result in increased costs with little safety benefit. MidAmerican commented that the ANPRM appeared to be based on an incorrect assumption that there are no current requirements applicable to non-HCA pipe; they noted that part 192 includes many requirements applicable to non-HCA segments and that they assure safety. Atmos suggested PHMSA avoid the ''one size fits all'' approach to pipeline safety regulations.

Response

PHMSA understands that assimilation of change is an important consideration and agrees that the ANPRM covers a number of complex issues. Many of the more complex issues contemplated in the ANPRM, such as leak detection and automatic valves, will be addressed by separate rulemaking so that more careful and detailed analysis can be completed. However, PHMSA is proposing rulemaking in a number of areas to assure that the regulations continue to provide an adequate level of safety for both HCAs and non-HCAs. Additional discussion of the basis for the proposed rulemaking is presented in the response to comments received for each ANPRM topic and in Section V below (Section-by-Section Analysis).

4. A number of industry commenters suggested that PHMSA exercise care in developing broad requirements that may be inappropriate for some types of pipelines. In particular, APGA noted that ''transmission'' pipeline operated by local distribution companies is very different from long-distance transmission lines. They are typically smaller diameter, operate at lower pressures, and are often made of plastic. AGA and distribution pipeline operators noted that leaks are a routine management issue for distribution pipelines and those requirements appropriate to leak response for transmission pipelines would not be appropriate in a distribution context. The Texas Oil & Gas Association requested that any changes be examined for possible unexpected impact on gathering lines, which also differ from transmission pipelines.

Response

PHMSA is aware of the varying nature of pipeline systems. One aspect of performance-based requirements is the ability of operators to customize the integrity management program so that it is appropriate to its circumstances.

5. AGA and some pipeline operators noted that the ANPRM suggested that PHMSA intends to extrapolate hazardous liquid pipeline experience to gas pipelines. In particular, they expressed concern regarding the discussion of leak detection. They noted pin-point leak detection may be practical for non-compressible liquids but is not for gas.

Response

PHMSA appreciates the significant differences between hazardous liquid pipelines and gas pipelines with respect to leak detection. PHMSA is sponsoring studies and research to address leak detection in a responsible way, while still being responsive to related NTSB recommendations. PHMSA is considering separate rulemaking for leak detection that will address these studies and research.

6. Pipeline industry trade associations reported that their members plan to implement voluntary approaches to improve pipeline safety. INGAA reported it has implemented a strategy to achieve a goal of zero pipeline incidents. This strategy includes voluntary application of IM principles to non-HCA pipeline segments where people live. Their goal is to apply ASME/ANSI B31.8S, Managing System Integrity of Gas Pipelines, principles to 90 percent of people who live or work in close proximity to pipelines by 2020, and 100 percent by 2030. INGAA's strategy also includes assuring the fitness for service of pipelines installed before federal safety regulations were promulgated, improving incident response time (to less than one hour in populated areas), and implementing the Pipelines and Informed Planning Alliance (PIPA) guidelines. AGA similarly reported their intentions to address improvements to safety proactively by applying Operator Qualification to new construction, continuing to advance IM principles (including developing industry guidelines for data management and data quality), and working with a coalition of PIPA stakeholders to adopt PIPA-recommended best practices, among other initiatives.

Response

PHMSA commends the pipeline industry for these initiatives and is committed to working with the industry to improve performance toward the goal of zero pipeline incidents.

7. A number of comments addressed the cost-benefit analyses that will be required in support of rulemaking that results from this ANPRM. AGA noted that a detailed estimate has not been completed but that preliminary evaluations suggest that the cost of implementing the initiatives included in the ANPRM could well exceed the cost of implementing the 2003 gas transmission IM rule. APGA agreed that some of the concepts discussed in the ANPRM are potentially very costly and must be considered carefully. Accufacts cautioned PHMSA to be wary of efforts to distort the cost-benefit analyses by hyper inflating costs. As an example, Accufacts pointed to estimates of costs to perform hydrostatic tests ranging from $500,000 to $1,000,000 per mile compared to costs of $29,400 to $40,000 per mile cited in the NTSB report on the San Bruno accident.

Response

PHMSA acknowledges that estimates of hydrostatic test costs can vary and that there is risk in using overstated estimates in the analysis of benefits and costs since regulatory decisions regarding public safety can be based on these results. For the Preliminary Regulatory Impact Assessment (PRIA) for this proposed rule PHMSA used vendor pricing data to develop unit costs for pressure testing. These costs represent the contractor's costs to complete an eight hour pressure test for

various segment diameters and lengths. PHMSA applied a multiplier to account for other operator costs, such as manifold installation and operational oversight, and also added estimated costs to provide temporary gas supplies and the market value of lost gas. Based on these data and assumptions, PHMSA estimated per mile pressure test costs range from approximately $60,000 per mile (12″ diameter, 10 mile segment) to 630,000 (36″ diameter, one mile segment). Detailed explanations of these unit costs are available in the PRIA, provided in the regulatory docket.

8. AGA and several pipeline operators suggested PHMSA should establish jointly with industry a committee to evaluate pipeline data and to determine whether more data is needed. They commented industry has repeatedly made this request and PHMSA has, to date, not responded. They contended PHMSA's current analysis of pipeline safety performance data is inadequate. Similarly, Panhandle Energy noted a number of the questions in the ANPRM requested data on various subjects; Panhandle expressed its belief that PHMSA collects and has access to at least some of data requested, and this data, collected pursuant to regulatory requirements, should be more complete, and consistently collected and reported, than piecemeal collections of data in response to this ANPRM. Expressing a somewhat contrary view, El Paso suggested more data should be collected and analyzed before notices of proposed rulemakings are prepared; PHMSA needs to collect and analyze data to determine the proper path for future requirements, if any.

Response

In response to NTSB recommendation P–11–19, PHMSA held a pipeline safety data workshop in January 2013. The workshop: (1) Summarized the data OPS collects, who it is collected from, and why it is collected; (2) addressed how stakeholders, including OPS, industry, and the public use the data; (3) addressed data quality improvement efforts and performance measures; and (4) discussed the best method(s) for collecting, analyzing, and ensuring transparency of additional data needed to improve performance measures. PHMSA considered the results of the workshop as well as the comments to the ANPRM related to pipeline safety performance data.

9. APGA suggested PHMSA revise the definitions of transmission and distribution pipelines to be more risk-based. APGA contended that the current definitions are not risk-based and lead to inappropriate outcomes. In particular, classification of some pipelines as ''transmission'' based on functional aspects of the current definition leads to inappropriate application of requirements. In a similar vein, Oleksa and Associates suggested it may be time to reduce IM requirements on low-stress transmission pipelines, which pose lower risk than high-stress lines. Texas Pipeline Association and Texas Oil & Gas Association commented PHMSA should not extrapolate experience with interstate pipelines to intrastate lines, which differ in design and operation.

Response

The definition of transmission vs. distribution pipelines and the applicability requirements for integrity management in High Consequence Areas is not within the scope of this proposed rule. The general topic of the scope and applicability of integrity management is addressed in the class location report which available in the docket.

10. Northern Natural Gas recommended all exemptions from one-call requirements be eliminated. They noted excavation damage remains, by far, the single greatest threat to pipeline safety and management of excavation damage, through one-call programs, has been demonstrated to be an effective means of countering that threat.

Response

This comment is not within the scope of the ANPRM topics. However, PHMSA has revised the pipeline safety regulations related to pipeline damage prevention programs, which includes one-call programs, in an final rule issued July 23, 2015 (80 FR 43836).

11. The Gas Processors Association, Texas Pipeline Association, and Texas Oil & Gas Association commented regarding current efforts to clarify the applicability of part 192 requirements, particularly requirements for distribution integrity management, to farm taps. They suggested PHMSA is engaged in an expansion of requirements in this area without notice or a demonstrated safety need. They suggested PHMSA initiate a rulemaking specifically to clarify requirements applicable to farm taps.

Response

Treatment of farm taps is not within the scope of the ANPRM topics. However, PHMSA has engaged in dialogue with industry on this topic and will continue to consider options to address this issue in a separate action.

12. Northern Natural Gas suggested PHMSA reduce the time allowed for conducting a baseline assessment in cases where a new HCA is found, tailored to the circumstances of the particular segment. Northern expressed its belief this would address threats to integrity in areas affecting population more quickly than current requirements.

Response

Currently, § 192.905(c) requires that newly identified HCAs be incorporated into the baseline assessment plan within one year. PHMSA does not currently have plans to address this requirement. However, periodically DOT or PHMSA seeks public input on retrospective review of existing regulations under Executive Order 13563. PHMSA encourages the commenter to raise this issue the next time DOT or PHMSA solicits comments on retrospective review of existing regulations.

13. Alliance Pipeline suggested many pipeline safety questions can be answered by applying INGAA's five guiding principles of pipeline safety. They noted INGAA has developed the Integrity Management-Continuous Improvement (IMCI) Initiative to implement these principles and suggested PHMSA actively engage with INGAA in developing workable solutions to pipeline safety issues.

Response

PHMSA appreciates the industry efforts to improve pipeline safety and is committed to working with all stakeholders toward this end.

14. Paiute Pipeline and Southwest Gas commented integrity management requirements have not been in effect long enough to gauge their effectiveness and decide whether additional changes are needed. The companies noted the first, baseline assessments of pipeline segments subject to those requirements are only now being completed. AGA and other pipeline operators agreed, noting IM is still new, operators are still refining their processes, and PHMSA should approach change with caution.

Response

While the first round of baseline assessments are only now being completed, the gas IM rule has been in place approximately 10 years. PHMSA expects that operator IM programs should have significantly matured in this timeframe.

15. Panhandle Energy suggested that PHMSA evaluate rule changes that could have prevented incidents which occurred in recent years. Any initiatives that would not have contributed to improved safety, they suggest, should be postponed or treated as lower priority activities. Panhandle suggested rulemaking without a sound basis is not

only ineffective but counterproductive in that it diverts resources that could have been used to improve safety. Questar Gas similarly commented PHMSA needs to minimize unnecessary activities that inappropriately divert safety resources. Questar also recommended that PHMSA explicitly consider the diversity within the regulated community.

Response

One of the major motivations for PHMSA's issuance of the ANPRM was to solicit information useful to ensuring that pipeline safety reforms have a sound basis. PHMSA is also required by Executive Orders 12866 and 13563 to ensure that the benefits of its rules justify the costs, to the extent permitted by law. PHMSA has prepared an initial regulatory impact analysis for this proposed rule, which is available in the docket for this rule. PHMSA encourages the commenter as well as other members of the public to review the analysis and provide input for improving the final rule.

16. AGA and several pipeline operators commented that, while enhancements can be made, IM requirements need not be subjected to wholesale change. They cited GAO and NTSB reports on the efficacy of transmission pipeline integrity management and the lack of pipeline safety issues among the NTSB's ''Most Wanted'' issues.

Response

While PHMSA believes that IM has led to improvements in managing pipeline integrity, recent incidents and accidents demonstrate that much work remains to improve pipeline safety.

17. AGA and pipeline operators noted that transmission and distribution integrity management are not distinct activities for most intrastate pipeline operators. They contended that the ANPRM seemed to be based on a presumption that operators manage their transmission and distribution pipeline safety differently, and that this assumption is without basis.

Response

PHMSA has promulgated specific IM rules for both transmission and distribution systems with a view toward allowing operators to customize their performance based programs as appropriate to their specific systems.

18. AGA and several pipeline operators suggested that any changes to public awareness requirements should be made at the state level. They noted that federal requirements in this area are new and that effectiveness reviews are still in progress.

Response

This issue is not within the scope of the ANPRM. However, PHMSA has revised the pipeline safety regulations related to pipeline damage prevention programs in a final rule issued July 23, 2015 (80 FR 43836).

19. NACE International suggested that adopting its standards for corrosion control would be the best means to accomplish the goal of maintaining pipelines safe and functional for long periods of time.

Response

This NPRM proposes to incorporate industry consensus standards into the regulations for assessing the physical condition of in-service pipelines using in-line inspection, internal corrosion direct assessment, and stress corrosion cracking direct assessment. In addition, this NPRM proposes to enhance subpart I requirements for corrosion control and to revise Appendix D to improve requirements for cathodic protection.

20. The NTSB commented that regulations for gas transmission pipelines can and should be improved and expressed its support for the overall intent of the ANPRM. The NTSB noted publication of the ANPRM prior to its recommendations resulting from the San Bruno incident investigation precluded any mention in the ANPRM of these NTSB safety recommendations. The NTSB suggested PHMSA should seek comment on its recommendations.

Response

PHMSA has reviewed the NTSB recommendations that were issued on September 26, 2011 and found that several recommendations related directly to the topics addressed in the ANPRM and that may impact the proposed approach to rulemaking. The topics impacted are discussed above in the Background section above, in sections II.C and II.E, and include NTSB Recommendations P–11–10, P–11–11, P–11–14, P–11–15, P–11–17, and P–11–19. The NTSB's other recommendations will be addressed in separate proceedings.

21. El Paso suggested that the proper approach to attain the highest pipeline safety levels is through a structured, deliberate rulemaking that closely examines all issue aspects prior to making informed decisions.

Response

PHMSA agrees and is taking a careful, structured, and phased approach to enhancing pipeline safety regulations and IM performance standards.

22. Thomas M. Lael, a pipeline industry consultant, suggested any new regulations be concise and clear. He contended past lack of clarity has created the need for many re-interpretations and enforcement problems.

Response

PHMSA concurs but also notes that performance-based regulations, by their nature, are not as specific, nor as easily measurable, as prescriptive regulations, but are more likely to improve safety and the cost-effectiveness of regulations. PHMSA provides guidance to help stakeholders understand the intent and scope of performance-based regulations.

General Public Comments

1. A member of the public stated that the ANPRM did not provide specific options for consideration. As written, only those with direct involvement in the industry could understand it well enough to comment. Presenting the options more specifically would allow for better informed public comment. The discussion should also include a regional component, since issues affecting different states/regions are not the same.

Response

By its nature, the ANPRM did not propose specific alternatives or rules, but solicited input to help inform future proposals. This NPRM provides specific proposed rules for public comment.

2. The Alaska Natural Gas Development Authority stated that the regulations should require consideration of earthquakes, as recent history shows they can be very important to safety of high-pressure gas lines.

Response

Section 29 of the Act states that in identifying and evaluating all potential threats to each pipeline segment, an operator of a pipeline facility shall consider the seismicity of the area. Rulemaking for this issue is addressed in this NPRM and would add requirements to explicitly reference seismicity for data gathering and integration, threat identification and implementation of preventive and mitigative measures.

3. The Environmental Defense Fund pointed out that methane is a very potent greenhouse gas. They commented that PHMSA should consider and minimize the potential environmental effects of any future rulemaking. They suggested EPA's Natural Gas Star program as a model.

Response

The proposals in this rulemaking are designed to minimize the risk of pipeline failures, which will result in environmental benefits. The draft environmental assessment addresses the environmental effects of this rulemaking.

In addition, the RIA provides estimates of the environmental benefits of this proposed rule. Natural gas transported in transmission pipelines contains heat-trapping gases that contribute to global climate change and its attendant societal costs. Of these gases, of primary importance for evaluation are methane—by far, the largest constituent of natural gas—and carbon dioxide. Other natural gas components (ethane, propane, etc.) contribute as well, but they account for a much smaller percentage of the natural gas mixture and, as a result, are much less significant than methane in terms of their environmental impact. The proposed rule is expected to prevent incidents, leaks, and other types of failures that might occur, thereby preventing future releases of greenhouse gases (GHG) to the atmosphere, thus avoiding additional contributions to global climate change. PHMSA estimated net GHG emissions abatement over 15 years of 69,000 to 122,000 metric tons of methane and 14,000 to 22,000 metric tons of carbon dioxide, based on the estimated number of incidents averted and emissions from pressure tests and ILI upgrades.

4. A member of the public questioned the openness and clarity of PHMSA's enforcement of pipeline safety regulations, and the use of civil penalty revenues.

Response

This comment is not within the scope of the ANPRM topics, however, it should be noted that PHMSA embraces transparency in its regulatory oversight program and has established a Pipeline Safety Stakeholder Communications Web site, *http://primis.phmsa.dot.gov/comm/*, which presents a variety of reports detailing enforcement activity. These reports are offered on both nationwide and operator-specific bases.

5. One member of the public suggested that DOT define ''safe corridors'' for above-ground construction of pipelines. The commenter suggested this would be similar, in principle, to the interstate highway system. It would help to keep pipelines separated from residences, avoid corrosive environments, and make pipelines available for routine direct examination. At a minimum, this commenter suggested the regulations should specify a minimum separation between new pipelines and residences, as does the New Jersey state code, or homebuyers be informed when a home is within the potential impact radius of a gas transmission pipeline so they may make an informed buying decision.

Response

This comment addresses pipeline siting and routing, which is outside the scope of PHMSA's statutory authority. As specified in 49 U.S.C. 60104, Requirements and Limitations of the Act, PHMSA is prohibited from regulating activities associated with locating and routing pipelines. Paragraph (e) of the statute states ''Location and routing of facilities.—This chapter does not authorize the Secretary of Transportation to prescribe the location or routing of a pipeline facility.'' However, PHMSA is an active participant in the Pipeline and Informed Planning Alliance (PIPA) and encourages all stakeholders to learn about, and become involved with, PIPA. More information can be obtained online at: *http://primis.phmsa.dot.gov/comm/pipa/landuseplanning.htm*.

6. One member of the public noted there is an increasing trend in significant incidents and suggested that this trend may be related to undue influence of the pipeline industry on the regulations under which it operates. The commenter recommended regulations should not be weakened in favor of industry. The League of Women Voters of Pennsylvania also recommended that regulatory agencies be insulated from political and other influences of natural gas pipeline companies to avoid the appearance of a conflict of interest.

Response

PHMSA appreciates these comments. PHMSA is committed to improving pipeline safety, and that is the goal of this endeavor. Significant incidents on Gas Transmission (GT) pipelines have averaged between 70 and 80 incidents per year over the past 9 years. The existing integrity management regulations in 49 CFR part 192, subpart O, addresses pipeline integrity in HCAs, which is only about 7 percent of the GT pipeline mileage. This proposed NPRM is focused on strengthening requirements in HCAs and applying integrity management principles to areas outside HCAs to better address safety issues. In addition, the proposed rule seeks to address significant issues that caused or contributed to the San Bruno accident, which include lack of pressure test, inadequate records, poor materials, and inadequate integrity assessment. The operator reports submitted to PHMSA as mandated by the Act confirm that these issues are widespread for both HCA and non-HCA pipe segments.

7. The Harris County Fire Marshall's Office (HCFM) suggested stiffer regulations are needed for gas transmission pipeline safety, because of the large potential for negative impact and catastrophic consequences. HCFM expressed concern about corrosion control and current inspection practices for aging transmission infrastructure.

Response

This NPRM proposes enhanced corrosion control requirements, including periodic close interval surveys, post construction surveys for coating damage, and interference current surveys. This NPRM also proposes enhanced requirements for internal corrosion and external corrosion management programs.

8. The Pipeline Safety Trust (PST) commented that the ANPRM, itself, may heighten and fuel existing public concerns about pipeline safety. PST noted that many of the questions asked the industry to provide information they believe the public would believe PHMSA should already have. PST expressed its view that the number and types of questions asked in the ANPRM reflect gaps in PHMSA's knowledge of gas transmission pipeline systems and operator practices.

Response

PHMSA appreciates these comments. PHMSA is committed to improving pipeline safety and stakeholder input is valuable to the regulatory process.

9. Professional Engineers in California Government (PECG) commented that private companies should not be solely responsible for the safety of their pipelines. PECG contended that this approach has not worked. PECG also suggested PHMSA examine options for increasing the number of inspectors at state pipeline regulatory agencies and require public inspectors be on site for pipeline construction and testing. They contended such inspection is necessary to assure that older pipelines are tested adequately and replaced when needed.

Response

PHMSA appreciates these comments. PHMSA is committed to ensuring that operators maintain and operate their pipelines safely. This rulemaking contains a number of measures aimed at enhancing oversight.

10. The City and County of San Francisco (CCSF) noted the scope of potential rulemaking discussed in the

ANPRM did not include consideration of PHMSA's coordination with and oversight of state certified agencies. In order to ensure the proper oversight over natural gas transmission operators and the safe operation of natural gas transmission lines, CCSF believes PHMSA must address its state certification program and its oversight of state enforcement of pipeline safety standards. CCSF recommended PHMSA publish regulations for certification of state programs. They cited NTSB recommendation P–11–20 and asserted PHMSA has not corrected inadequate practices of the California Public Utilities Commission.

Response

This comment is outside the scope of this rulemaking. PHMSA is addressing NTSB recommendation P–11–20 separately.

11. Two members of the public suggested the processes of the Federal Energy Regulatory Commission (FERC) for siting pipelines should be revised. One suggested a Commission on Public Accountability and Safety Standards be established, consisting of a majority of local public officials, first responder experts, and independent qualified engineers, to make recommendations for FERC's pre-application process and standards. The purpose would be to assure standards require public accountability for review and vetting of pipeline safety issues with local authorities when pipelines are proposed. The other commenter suggested the relationship between FERC and DOT should be clarified, that a company's enforcement history be taken into account in siting decisions, and PHMSA be a full party to all FERC proceedings. The commenter believes this is necessary because FERC does not have a public safety mandate.

Response

PHMSA is a separate agency from FERC and has no statutory authority with respect to pipeline siting or approval. As specified in 49 U.S.C. 60104, Requirements and Limitations of the Act, PHMSA is prohibited from regulating activities associated with locating and routing pipelines. Paragraph (e) of the statute states ''Location and routing of facilities.—This chapter does not authorize the Secretary of Transportation to prescribe the location or routing of a pipeline facility.'' However, PHMSA is an active participant in the Pipeline and Informed Planning Alliance (PIPA) and encourages all stakeholders to learn about, and become involved with, PIPA. More information can be obtained online at: *http://primis.phmsa.dot.gov/comm/pipa/landuseplanning.htm.*

12. Two members of the public commented federal regulations should not override local ordinances. They noted the concern of local authorities is safety, while others are concerned about industry costs. They believe federal regulations that allow operators significant discretion are a poor basis to supersede specific local requirements.

Response

PHMSA appreciates these comments. Federal regulations provide for a uniform body of standards and requirements related to pipeline safety. PHMSA is receptive to input from state and local authorities on pipeline safety issues. States and local authorities may adopt requirements that are more stringent than and consistent with the federal regulations for their intrastate pipelines if they have a 49 U.S.C. 60105 certification.

13. One member of the public suggested regulations require periodic safety audits by an auditor not selected by the pipeline operator. The commenter further suggested that local authorities should have approval authority in the choice of the auditor. The commenter contended this approach would strengthen public confidence in pipeline safety.

Response

PHMSA appreciates this comment. Highly trained federal and state pipeline inspectors conduct inspections of pipeline operators, their facilities, and their compliance programs on a regular basis.

Comments on ANPRM Section II Topics on Which PHMSA Sought Comment

In section II of the ANPRM, commenters were urged to consider whether additional safety measures are necessary to increase the level of safety for those pipelines that are in non-HCA areas as well as whether the current IM requirements need to be clarified and in some cases enhanced to assure that they continue to provide an adequate level of safety in HCAs. PHMSA posed specific questions to solicit stakeholder input. These included questions related to the following topics:

A. Modifying the Definition of HCA,
B. Strengthening Requirements to Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs,
C. Modifying Repair Criteria,
D. Improving Requirements for Collecting, Validating, and Integrating Pipeline Data,
E. Making requirements Related to the Nature and Application of Risk Models More Prescriptive,
F. Strengthening Requirements for Applying Knowledge Gained Through the IM Program
G. Strengthening Requirements on the Selection and Use of Assessment Methods,
H. Valve Spacing and the Need for Remotely or Automatically Controlled Valves,
I. Corrosion Control,
J. Pipe Manufactured Using Longitudinal Weld Seams,
K. Establishing Requirements Applicable to Underground Gas Storage,
L. Management of Change,
M. Quality Management Systems (QMS),
N. Exemption of Facilities Installed Prior to the Regulations,
O. Modifying the Regulation of Gas Gathering Lines.

Each topic is summarized as presented in the ANPRM, then general comments related to the topic are presented, followed by each individual question and comments received for the question.

A. Modifying the Definition of HCA

The ANPRM stated that ''IM requirements in subpart O of part 192 specify how pipeline operators must identify, prioritize, assess, evaluate, repair and validate; *[sic]* through comprehensive analyses, the integrity of gas transmission pipelines in HCAs. Although operators may voluntarily apply IM practices to pipeline segments that are not in HCAs, the regulations do not require operators to do so. A gas transmission pipeline ruptured in San Bruno, California on September 9, 2010, resulting in eight deaths and considerable property damage. As a result of this event, public concern has been raised regarding whether safety requirements applicable to pipe in populated areas can be improved. PHMSA is thus considering expanding the definition of an HCA so that more miles of pipe are subject to IM requirements.'' The ANPRM then listed questions for consideration and comment. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic A

1. INGAA and a number of pipeline operators noted this is an opportune time for considering the next steps in integrity management, since baseline assessments under the current IM rules are now being completed. INGAA noted its policy goal is to apply IM principles

(as described in ASME/ANSI B31.8S) beyond HCAs, covering 90 percent of people living near transmission pipelines by 2020 and 100 percent by 2030. TransCanada submitted information in support of INGAA's proposal, noting that by the end of 2012 the company will have assessed more than 85 percent of its US pipeline mileage covering more than 95 percent of people living near their pipelines. Thus, the current IM rules are having a significant positive impact on pipeline safety. TransCanada believes significant technological challenges would be encountered if IM regulations were extended to all pipelines.

2. MidAmerican commented it would be reasonable to differentiate between transmission pipelines operating above and below 30 percent specified minimum yield strength (SMYS) in terms of IM requirements. They estimated that less than 3 percent of local distribution company (LDC) transmission lines operate at greater than 30 percent SMYS.

3. MidAmerican and a member of the public suggested PHMSA eliminate class locations in favor of better-defined HCAs. They contend such a change would result in administrative savings for pipeline operators.

4. Southwest Gas and Paiute commented no new regulations should be promulgated in this area until the study required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 is completed.

Response to General Comments for Topic A

PHMSA appreciates the information provided by the commenters. Section 5 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act) (Pub. L. 112–90) requires the Secretary of Transportation to ''evaluate (1) whether integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas; and (2) with respect to gas transmission pipeline facilities, whether applying integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.'' PHMSA has completed the report mandated by the Act that documents that evaluation and addresses whether integrity management (IM) program requirements should be expanded beyond high consequence areas (HCAs) and, specifically for gas transmission pipelines regulated under 49 Code of Federal Regulations (CFR) part 192, whether such expansion would mitigate the need for class location designations and corresponding requirements. The class location report is available for review in the docket.

In October 2010 and August 2011, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published notices in the **Federal Register** to solicit comments on revising the pipeline safety regulations applicable to hazardous liquid and natural gas transmission pipelines including expansion of IM program requirements beyond HCAs. In general, industry representatives and pipeline operators were opposed to any expansion of HCAs and in favor of eliminating class locations on newly constructed pipelines, whereas public interest groups were in favor of expanding HCA but against curtailing class location requirements.

PHMSA has carefully considered the input and comments. At this time PHMSA plans to propose an approach that balances the need to provide additional protections for persons within the potential impact radius (PIR) of a pipeline rupture (outside of a defined HCA), and the need to prudently apply IM resources in a fashion that continues to emphasize the risk priority of HCAs. PHMSA, therefore, is considering an approach that would require selected aspects of IM programs (namely, integrity assessments and repair criteria) to be applicable for non-HCA segments. For hazardous liquid pipelines, PHMSA would propose to apply these requirements to non-HCA pipeline segments. For gas transmission pipelines, PHMSA would propose to apply these requirements where persons live and work and could reasonably be expected to be located within a pipeline PIR. Under this approach, PHMSA would propose requirements that integrity assessments be conducted, and that injurious anomalies and defects be repaired in a timely manner, using similar standards in place for HCAs. However, the other program elements of a full IM program contained in 49 CFR part 192, subpart O, or 49 CFR 195.452 (as applicable) would not be required for non-HCA segments.

The Act also required the Secretary of Transportation to evaluate if expanding IM outside of HCAs, as discussed above, would mitigate the need for class location requirements. In August 2013, PHMSA published a notice in the **Federal Register** (78 FR 53086) soliciting comments on expanding IM program requirements and mitigating class location requirements. In addition, PHMSA held a Class Location Workshop on April 16, 2014, to discuss the notice and comments were received from stakeholders, including industry representatives, pipeline operators, state regulatory agencies, and the public. Overall, the majority of stakeholder responses suggested that PHMSA not change the current class location approach for class locations and class location changes as population increases used for establishing MAOP and operation and maintenance (O&M) surveys for existing pipelines. For new transmission pipelines, some industry groups and operators supported some type of bifurcated approach for existing and new pipelines as described above.

Based upon stakeholder input and findings from lessons learned, incident investigations, assessments, IM, and operating, maintenance, design and construction considerations, PHMSA believes the application of integrity management assessment and remediation requirements to MCAs does not warrant elimination of class locations. Class locations affect all gas pipelines, including transmission (interstate and intrastate), gathering, and distribution pipelines, whether they are constructed of steel pipe or plastic pipe. Class location is integral to determining MAOPs, design pressures, pipeline repairs, high consequence areas (HCAs), and operating and maintenance inspections and surveillance intervals. Class locations affect 12 subparts and 28 sections of 49 CFR part 192 for gas pipelines. The subparts and sections are listed and discussed in Sections 3.1.2.4 and 3.7.2.2. While assessment and remediation of defects on gas transmission pipelines is an important risk mitigation program, it does not adequately compensate for other aspects of class location as it relates to other types of gas pipelines and as it relates (for all gas pipelines) to the original pipeline design and construction such as the design factor, initial pressure testing, establishment of MAOP, O&M activities, and other aspects of pipeline safety, that are based on class location. Thus, PHMSA has determined not to eliminate class location requirements.

With respect to the application of gas transmission IM requirements to pipeline operating at less than 30% SMYS, as part of its consideration of the issues discussed in Topics J and N, PHMSA considered but rejected the suggestion that pipelines operating less than 30% SMYS be differentiated from those operating at higher stress levels.

Comments submitted for questions in Topic A.

A.1—Should PHMSA revise the existing criteria for identifying HCAs to expand the miles of pipeline included in HCAs? If so, what amendments to the criteria should PHMSA consider (e.g.,

increasing the number of buildings intended for human occupancy in Method 2?) Have improvements in assessment technology during the past few years led to changes in the cost of assessing pipelines? Given that most non-HCA mileage is already subjected to in-line inspection (ILI), does the contemplated expansion of HCAs represent any additional cost for conducting integrity assessments? If so, what are those costs? How would amendments to the current criteria impact state and local governments and other entities?

1. INGAA, industry consultant Thomas Lael, and a number of pipeline operators commented that modification of the HCA definition is unnecessary. They contended that the current definition is already risk-based and provides an effective basis for IM requirements along with a reasonable point from which to expand the application of IM principles by voluntary action. Accufacts commented that PHMSA should focus on closing gaps and loopholes rather than increasing HCA mileage, and that increasing covered mileage would only create the illusion of more safety.

2. AGA, APGA, and a number of gas distribution pipeline operators also opposed changes to the definition. They commented that other requirements of part 192 already address the primary threats for pipe outside HCA. They noted that much effort went into establishing the current definition, there is no safety rationale to abandon it, and change would be inconsistent with risk-based principles and would dilute safety efforts. AGA further noted that imprudent expansion would be contrary to Congressional intent, in that it would dilute the focus on densely populated and environmentally sensitive areas. AGA commented that PHMSA should make no change in this area before completing the related studies required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.

3. Taking a contrary position, a number of commenters not affiliated with the pipeline industry supported increasing the pipeline mileage classified as HCA. One private citizen suggested that all pipelines in cities with population greater than 100,000 should be classified as HCA. This commenter believes that existing regulations result in insufficient requirements for urban pipelines. Another citizen suggested that all high-stress lines with a ''receptor,'' which he defines as ''something which needs to be protected,'' should be assessed. If changes to the HCA definition are needed to accomplish this, then he contended those changes should be made. The Pipeline Safety Trust would strengthen IM requirements and expand them to all transmission pipelines, although they allow that the details could be different for pipelines not currently classified as HCA. PST believes this would be an effective way to identify and eliminate threats.

4. The Oklahoma Independent Petroleum Association (OKIPA) commented that any changes to the HCA definition must be supported by a scientifically-valid assessment of risks and a complete cost-benefit analysis.

5. The Iowa Association of Municipal Utilities commented that PHMSA should not revise the HCA definition without taking into account the differences between high-pressure transmission pipelines and low-pressure, low-risk lines that are also classified as transmission. IAMU reported ''transmission lines'' operated by Iowa Municipal Utilities are typically 2 to 4 inches in diameter and have potential impact radii less than 90 feet.

6. The Texas Pipeline Association and Texas Oil & Gas Association contended that expanding HCA pipeline mileage would increase assessment costs, particularly if the arbitrary requirement for reassessments every 7 years is not changed. These associations also believe that additional assessments will result in significant service interruptions. They suggested that assessment requirements be expanded to other pipelines, if needed, rather than changing the definition of HCA, contending that this would allow a more reasoned approach not burdened by the requirement for 7-year reassessments.

7. The Texas Pipeline Association, Texas Oil & Gas Association and several pipeline operators disagreed with the ANPRM assertion that most non-HCA transmission pipeline has been subject to ILI inspections. They noted much non-HCA pipeline has been pigged (*i.e.,* assessed using an in-line inspection tool) but that intrastate transmission pipelines are typically not piggable.

8. MidAmerican suggested that there is no reason to believe that changes to the HCA definition would improve safety. They also noted that the effects of other recent regulatory changes have not yet been realized and could mask any effect of changes in HCA. At the same time, the company noted that revising the definition of an HCA to encompass potential impact circles with 15 structures intended for human occupancy, vs. the current 20, would increase the amount of HCA mileage on its pipeline system by about 10 percent, contending that the safety benefit of such a change would be questionable. They suggested it would be better to focus on pipe in HCAs rather than adding lower-risk pipe, since part 192 already provides a good level of safety for all pipelines.

9. INGAA and a number of pipeline operators commented that increasing the amount of HCA mileage would add or increase costs for hundreds of state and local government agencies. The increases would result from increased demands for identification, certification, and compliance auditing.

10. Northern Natural Gas suggested that PHMSA consider expanding HCA coverage by modifying the specifics of Method 2 for defining HCAs over time. Changes could include reducing the number of structures in potential impact circles that define an HCA, reducing the number of people that defines an identified site, etc. The company believes this kind of change would have the benefit of continued use of the ''science'' represented by the C–FER Technologies circle for determining HCAs (see part 192, appendix E, figure E.I.A). Northern also suggested PHMSA define a time period for occupation of an identified site which, they contended, would eliminate the need to address locations where a gathering of people is truly transient.

11. TransCanada reported its belief that the current HCA criteria provide an appropriate risk focus. In support of this belief, they noted that only 3 percent of their US transmission pipeline mileage is in HCAs but this includes 45 percent of the population within a potential impact radius of their pipelines.

12. The Iowa Utilities Board opposed changes to the HCA criteria to encompass more mileage. IUB commented that such changes would divert resources from application to higher-risk pipeline segments and there has been no demonstration that non-HCA pipeline segments pose as much risk as those currently defined as HCA.

13. Two private citizens and the Commissioners of Wyoming County, Pennsylvania, suggested the existence of one structure intended for human occupancy within a potential impact circle should be sufficient to define an HCA. These commenters noted that catastrophic consequences (*i.e.,* loss of life) are still possible in such sparsely populated areas. The Commissioners noted homes in their jurisdiction generally did not encroach on the pipelines; the homes were there first and the pipeline encroached on what should have been a safe zone around the home. They implied pipeline operators should expect a higher burden to assure safety in such circumstances.

14. The Pipeline Safety Trust commented that there should be a single set of criteria defining HCAs and that these criteria should be known to the public. They contended the public currently has no information on the criteria defining HCAs.

15. The California Public Utilities Commission commented that HCA criteria should be revised to include more pipeline mileage and that method 2 (use of potential impact circles) should be eliminated.

16. The Alaska Natural Gas Development Authority suggested that the definition of an HCA should accommodate the phenomenon of rapid growth in previously rural areas. They noted that such growth has occurred within Alaska due, in part, to disposal of state lands.

17. NAPSR suggested that PHMSA require all transmission pipelines to meet Class 3 and 4 requirements and eliminate HCAs. NAPSR contended that focusing resources on higher-risk pipelines is bad public policy, since an accident anywhere poses a risk to public safety and reduces public confidence.

18. The Texas Pipeline Association, Texas Oil & Gas Association and several pipeline operators objected to the implication in the ANPRM that assessment costs have decreased. They contended that costs have actually increased due to such factors as operational cost escalation and increased costs to address cased pipeline segments.

19. INGAA and a number of pipeline operators contended that costs cannot be estimated accurately absent a specific regulatory proposal. They suggested that additional costs would be minimal if expanding HCA mileage results in actions similar to INGAA's Integrity Management—Continuous Improvement (IMCI) action plan, but that costs could be high if different requirements are imposed.

20. INGAA reported that a recent survey showed that its members' identified baseline IM assessments will cover 64 percent of members' pipeline mileage, only 4 percent of which is in HCAs. INGAA stated that these assessments will have covered 90 percent of the population within a potential impact radius of the pipelines.

21. Southwest Gas and Paiute provided cost estimates for conducting IM assessments on their pipeline systems: $45,000 per mile for direct assessment, up to $125,000 per mile for in-line inspection, and from $200,000 to $2 million per instance where changes need to be made to a pipeline to accommodate instrumented pigs.

22. The California Public Utilities Commission and MidAmerican commented that costs would increase if the changes suggested in the ANPRM were made, but they provided no specific estimates.

23. APGA noted that costs incurred by or passed on to municipal utilities are costs to local governments, since the utilities are, themselves, government agencies.

24. Paiute and Southwest Gas noted that costs to local governments, including preparation of permits, paving repairs, etc., can be high.

25. An anonymous commenter suggested that costs are not likely to increase much, since most operators already assess more than HCAs and IM has fostered growth in ILI vendors.

26. Kern River noted that its costs would not increase much, since the company is already under similar restrictive requirements via special permit.

27. Accufacts noted that safety is not free. They suggested that relative ranking of assessment methods, by cost, is not likely to have changed. They cautioned that costs used in cost-benefit analyses supporting any rules must be credible and should have an auditable trail available to the public. They suggested that serious accidents can be a ''cost'' of associated deregulation and lack of proper, effective, and efficient safety regulatory oversight for this critical infrastructure.

Response to Question A.1 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that the definition of HCAs is adequate, and does not propose to modify the definition of scope of HCAs in this proposed rulemaking. However, to afford additional protections to other segments along the pipeline, PHMSA is proposing to apply selected IM program elements (namely assessment and remediation of defects) to areas outside HCAs that are newly defined as MCAs. PHMSA believe this approach applies appropriate risk-based levels of safety.

A.2. Should the HCA definition be revised so that all Class 3 and 4 locations are subject to the IM requirements? What has experience shown concerning the HCA mileage identified through present methods (e.g., number of HCA miles relative to system mileage or mileage in Class 3 and 4 locations)? Should the width used for determining class location for pipelines over 24 inches in diameter that operate above 1000 psig be increased? How many miles of HCA covered segments are Class 1, 2, 3, and 4? How many miles of Class 2, 3, and 4 pipe do operators have that are not within HCAs?

A.3. Of the 19,004 miles of pipe that are identified as being within an HCA, how many miles are in Class 1 or 2 locations?

1. Industry trade associations, pipeline operators, and the Iowa Utilities Board objected to the suggestion all Class 3 and 4 locations should be treated as HCA. They noted class location does not have a direct relationship to risk. Small, low-pressure pipelines with no structures intended for human occupancy within the PIR (or for which the PIR is contained entirely within the right of way) could be Class 3 or 4 under current definitions. INGAA noted approximately 90 percent of Class 3 and 4 mileage not in HCA is presently assessed through over testing during IM assessments. Kern River commented that class location is an outmoded system that is confusing and unduly complex. Many of these commenters noted there is no demonstration of need for including all Class 3 and 4 areas, since existing HCA criteria adequately identify areas posing higher risks.

2. Public commenters took a contrary position, suggesting class locations are a reasonable basis for increasing HCA mileage. Pipeline Safety Trust and California Public Utilities Commission commented all Class 3 and 4 locations should be HCA. They noted these are all highly populated areas putting more people at risk from pipeline accidents. CPUC noted the location of the significant 2010 pipeline accident in San Bruno, CA, could have avoided HCA classification if method 2 of the current definition had been used. An anonymous commenter supported this position, suggesting all Class 3 and 4 locations be treated as HCA and use of method 2 be restricted to Class 1 and 2 locations; this commenter contended use of method 2 to exclude some portions of Class 3 and 4 locations from HCA classification is inappropriate. This commenter further suggested the definition of Class 4 locations be revised, contending that the criterion of 4-story buildings being ''prevalent'' is not specific enough. Thomas Lael, an industry consultant, suggested all Class 4 locations should be HCA. Lael contended that this would be an easy change and would assure that the highest risk pipe is included.

3. NAPSR also suggested all Class 3 and 4 locations should be classified as HCA. NAPSR noted this is an alternative to their preferred solution of eliminating HCA and requiring that all transmission pipelines meet Class 3 and 4 requirements.

4. One public commenter went further. He suggested a new classification, Class 5, be established encompassing all pipeline in cities with populations of more than 100,000. He further suggested pipe in this new class should meet enhanced construction requirements, including required installation of automatic valves to isolate the pipeline in the event of an incident. He contended the existing regulations impose inadequate safety requirements on urban pipelines.

5. Accufacts suggested PHMSA focus first on closing loopholes and gaps rather than increasing HCA mileage. They commented increasing covered mileage without closing gaps would produce only the illusion of safety.

6. Northern Natural Gas suggested PHMSA consider an option of eliminating method 2 of the current HCA definition. They contended such a change would be easy to accomplish. At the same time, they questioned its efficacy, suggesting that it would result in limited or no increase in safety while imposing large costs.

7. INGAA and many pipeline operators objected to the suggested increase in the width of a class location unit for larger, high-pressure pipelines. They noted such a change would contravene the goals of IM and divert resources to pipe of lower risk, and pipe of this type posing high risks to population concentrations is already included as HCA based on its potential impact radius (which could be larger than 220 yards).

8. Here, again, public commenters generally took a contrary position. Pipeline Safety Trust suggested class location width should be at least as much as the potential impact radius. PST noted the PIR is intended to focus on areas requiring more protection while the existing class location width is arbitrary. Two private citizens agreed, one noting that large-diameter, high-pressure gathering pipelines in the Marcellus shale area are located slightly more than 220 yards from pre-existing houses and the other suggesting the class location width in higher-class areas should be 220 yards or the PIR, whichever is larger. Accufacts would go further, suggesting class location width be increased for large-diameter pipe regardless of pressure. Accufacts contended diameter is a more significant factor in determining the potential extent of post-accident damage than is pressure, noting the devastation resulting from the San Bruno accident extended to a much greater distance than the PIR. The Texas Pipeline Association and Texas Oil & Gas Association commented no change should be made until the studies required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 are completed.

9. INGAA and a number of pipeline companies submitted data concerning the amount of pipeline mileage currently in HCAs. INGAA's data is based on a survey of its members.

	INGAA	Paiute	SWGas	MidAmerican	Northern Natural
Class 1	475 miles HCA, 103,286 not.	1 mile HCA, 632 not	<1 of 382 miles are HCA.	0.63 miles HCA, 493.11 not.	0.1% of all mileage is HCA.
Class 2	535 miles HCA, 11,318 not.	0 miles HCA, 55 not	<1 of 20 miles are HCA	0.98 miles HCA, 101.92 not.	2% of mileage is HCA.
Class 3	4,100 miles HCA, 4, 646 not.	26 miles HCA, 142 not	185 miles HCA, 242 not.	44.96 miles HCA, 128.38 not.	27% of mileage is HCA.
Class 4	24 miles HCA, 5 not	None of less than 1 mile is HCA.	6 miles HCA, 5 not	no HCA mileage	no data reported.

10. Iowa Association of Municipal Utilities reported its members have zero HCA miles in any class. Most member transmission pipelines are in Class 1 locations. Members have 1.46 miles of Class 2 pipe and one mile in Class 3.

11. Ameren Illinois reported 3.5 of its 82 HCA miles are in Class 1 or 2.

12. Kern River reported it has 18.51 HCA miles in Class 1 and 3.14 miles in Class 2, of a total of 95.96 miles of HCA.

13. On March 15, 2012, PHMSA received a petition for rulemaking from the Jersey City Mayor's office contending that the current Class Location system ''does not sufficiently reflect high density urban areas, as the regulation fails to contemplate either (1) the dramatic differences in population densities between highly congested areas and other less dense Class 4 Locations, or (2) the full continuum of population densities found in urban areas themselves.'' Based on this, Jersey City petitioned PHMSA to add three (3) new Class Locations, which would be defined as follows:

• A Class 5 location is any class location unit that includes one or more building(s) with between four (4) and eight (8) stories;

• A Class 6 location is any class location unit that includes one or more building(s) with between nine (9) and forty (40) stories;

• A Class 7 location is any class location unit that includes at least one building with at least forty-one (41) stories.

Response to Questions A.2 and A.3 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that HCAs should not be based exclusively on class location. Similarly, PHMSA does not propose to define MCAs based on class location. PHMSA proposes that *moderate consequence area* means an onshore area that is within a potential impact circle, as defined in § 192.903, containing five (5) or more buildings intended for human occupancy, an occupied site, or a right-of-way for a designated interstate, freeway, expressway, and other principal 4-lane arterial roadway as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures,* and does not meet the definition of high consequence area, as defined in § 192.903. This assures a comparable level of safety for all pipelines, regardless of class location. As a result, PHMSA is not proposing to expand class locations in this proposed rule. The issue of expanding class locations is addressed in the class location report which is available for review in the docket while formulating comments.

A.4. Do existing criteria capture any HCAs that, based on risk, do not provide a substantial benefit for inclusion as an HCA? If so, what are those criteria? Should PHMSA amend the existing criteria in any way which could better focus the identification of an HCA based on risk while minimizing costs? If so, how? Would it be more beneficial to include more miles of pipeline under existing HCA IM procedures, or, to focus more intense safety measures on the highest risk, highest consequence areas or something else? If so why?

1. INGAA and several pipeline operators commented the method described in paragraph 2 in the

definition of HCA in § 192.903 appropriately focuses attention on at-risk populations. They contended that the method described in paragraph 1 in the definition of HCA in § 192.903 captures some inappropriate areas.

2. Texas Pipeline Association, Texas Oil & Gas Association, and Ameren Illinois contended the existing criteria do not capture areas not posing risk. They noted the criteria were based on the science of pipeline accidents to identify high-risk areas.

3. Paiute and Southwest Gas commented neither more HCA miles nor additional safety measures are needed. They contended existing criteria are adequate and rule provisions for preventive and mitigative measures and to consider pipe with similar conditions when anomalies are found in HCA are sufficient to address non-HCA pipeline segments.

4. APGA recommended the regulations be modified to treat transmission pipelines operated by local distribution companies, most of which operate at less than 30 percent SMYS, under distribution integrity management rather than transmission IM. APGA suggested this is an optimum time to make this change, which was discussed in the phase 1 work leading up to the distribution IM rule. Atmos agreed, noting failure by leakage rather than rupture, similar to distribution pipelines, is much more prevalent for this low-stress pipeline and it thus poses much lower risks.

5. Northern Natural Gas suggested PHMSA revisit its treatment of ''well defined areas'' that constitute identified sites. They contended current practice treats an entire area as an identified site even if only an unoccupied corner is within the PIR and persons congregating are outside that critical radius.

6. MidAmerican suggested PHMSA consider adding a multiplier to the PIR equation for higher-stress pipelines. They contended this could capture more high-risk pipe without adversely affecting low-stress pipelines that pose considerably less risk.

7. Atmos commented no change should be made which would increase the amount of HCA mileage, contending that this would dilute the current focus on high-risk pipe.

8. INGAA and several of its members suggested PHMSA rely on its Integrity Management—Continuous Improvement (IMCI) initiative to address pipeline in non-HCA areas.

Response to Question A.4 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that the existing method for identifying HCAs and calculating PIR is appropriate and is not proposing a change to either. However, PHMSA disagrees that existing requirements are sufficient for non-HCAs segments. PHMSA believes non-HCA segments where people congregate should be afforded additional protections. Therefore, PHMSA is proposing that selected IM program elements (assessment and remediation of defects) be applied to MCAs.

A.5. In determining whether areas surrounding pipeline right-of-ways meet the HCA criteria as set forth in part 192, is the potential impact radius sufficient to protect the public in the event of a gas pipeline leak or rupture? Are there ways that PHMSA can improve the process of right-of-ways HCA criteria determinations?

1. INGAA, AGA, GPTC and a number of pipeline operators contended the existing PIR criteria are sufficiently conservative. They noted the criteria were derived from scientific analysis of the consequences of past pipeline accidents. Texas Pipeline Association and Texas Oil & Gas Association commented there is no reason to modify the PIR criteria or to establish alternate criteria to define HCAs; they contended there is no evidence the current PIR definition has provided insufficient protection to the public.

2. One private citizen and Alaska's Department of Natural Resources suggested HCA criteria should be revised to consider parallel pipelines in a common right of way, contending that an accident on one pipeline could impact adjacent lines, thus compounding consequences. They further suggested requirements for pipelines in common rights of way should include minimum spacing between the pipelines.

3. An anonymous commenter suggested plume releases be considered to determine which pipeline segments can affect an HCA, contending that this would be a good practice.

4. AGA, Texas Pipeline Association, Texas Oil & Gas Association, GPTC, and several pipeline operators cautioned against use of the term ''right of way'' in the context of defining HCAs. They noted this term is imprecise and the actual location of the pipeline, rather than an ill-defined right of way, is the important factor in evaluating risk.

5. Accufacts, INGAA, and numerous pipeline operators cautioned against discussions that imply that the PIR concept is applicable to considerations of risk from pipeline leaks. These commenters noted that the PIR is based on the consequences of a pipeline rupture and resulting conflagrations and was never intended to address leaks not involving fires.

6. ITT Exelis Geospatial Systems, a company providing services to the pipeline industry, noted accurate location of a pipeline is as important to assuring adequate protection of high-risk populations as is the calculation of PIR.

7. Accufacts suggested PHMSA require a report of the actual impact area, including aerial photographs, within 24 hours of any pipeline rupture. Accufacts contended this data would provide a further basis for continuing review of PIR adequacy.

Response to Question A.5 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that the existing definition of PIR is appropriate at this time. PHMSA believes that adjusting the PIR formula based on parallel pipelines in the right-of-way, or other right-of-way factors, are premature at this time. Also, PHMSA acknowledges that the PIR approach only applies such incidents resulting in explosions and fires. While certain gases might be better modeled using plume models, such models have not been carefully studied or developed. However, PHMSA plans to pursue (outside the scope of this rulemaking) additional incident reporting requirements for the purpose of further evaluating the extent of damage following incidents.

A.6. Some pipelines are located in right-of-ways also used, or paralleling those, for electric transmission lines serving sizable communities. Should HCA criteria be revised to capture such critical infrastructure that is potentially at risk from a pipeline incident?

1. INGAA, AGA, Texas Pipeline Association, Texas Oil & Gas Association, and many pipeline operators objected to any potential inclusion of ''critical infrastructure'' in HCA criteria. They noted there is no history of problems caused by impacts on infrastructure, there is little public risk involved, data regarding such infrastructure would be difficult for pipeline operators to obtain, and issues involving potential interactions with critical infrastructure are usually addressed during pipeline planning and construction.

2. GPTC and Nicor recommended HCA criteria not be revised to include critical infrastructure. They noted the intent of defining HCAs is to address risk to life and not property damage and damages to local infrastructure are unlikely to result in consequences similar to those that could affect population concentrations near the

pipeline. Atmos agreed, noting planning for accident-caused outages is a responsibility of electric system operators.

3. Pipeline Safety Trust, Accufacts, NAPSR, Alaska Department of Natural Resources, California Public Utilities Commission and ITT Exelis Geospatial Systems recommended critical infrastructure be included among HCA-defining criteria. Several of these commenters suggested infrastructure beyond electric transmission be considered, including, for example, water and sewage treatment plants, fire stations, and communications facilities. The commenters noted damages to critical infrastructure can lead to cascading effects and additional public safety consequences. ITT Exelis acknowledged these considerations may be secondary to loss of life but contended they are still important to public safety.

4. Northern Natural Gas, Kern River, MidAmerican, Paiute, and Southwest Gas noted determining the impact of damages to infrastructure items is complex. These commenters suggested it is not practical to define what constitutes ''critical'' infrastructure, from a public safety standpoint, on a generic basis. They recommended PHMSA leave consequence determination to operators, as part of their risk assessments, providing additional guidance for such considerations if needed.

5. An anonymous commenter suggested more frequent tests of cathodic protection and coating surveys be required in areas potentially subject to induced currents from nearby electric transmission infrastructure.

Response to Question A.6 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that there have been relatively few pipeline incidents that have had a major impact on critical infrastructure. PHMSA also acknowledges that the PIR formula was developed based on life safety (*i.e.,* heat flux that result in fatalities). However, PHMSA is also aware of recent incidents that, among other consequences, damaged and caused temporary closure of interstate highways. Among them are the 2012 incident at Sissonville, WV and the 2010 incident at New Delhi, LA, which also resulted in one fatality. Even though PHMSA is not proposing to revise the HCA criteria or the PIR formula, PHMSA is proposing to include major highways in the MCA criteria.

A.7. What, if any, input and/or oversight should the general public and/or local communities provide in the identification of HCAs? If commenters believe that the public or local communities should provide input and/or oversight, how should PHMSA gather information and interface with these entities? If commenters believe that the public or local communities should provide input and/or oversight, what type of information should be provided and should it be voluntary to do so? If commenters believe that the public or local communities should provide input, what would be the burden entailed in providing provide this information? Should state and local governments be involved in the HCA identification and oversight process? If commenters believe that state and local governments be involved in the HCA identification and oversight process what would the nature of this involvement be?

1. INGAA and its pipeline operator members commented no additional public involvement is needed. INGAA noted consultation is required under the current regulations, and it seldom identifies any relevant information. Additional involvement, INGAA contends, would likely lead to inconsistencies and would degrade the technical/scientific basis for determining HCAs.

2. AGA and several of its member companies suggested local government agencies should provide information when requested by pipeline operators. They contended additional required involvement would pose an additional burden on pipeline operators while adding no benefit. AGA noted information from its members suggests that local government agencies very rarely point out identified sites not otherwise known to the pipeline operator.

3. Texas Pipeline Association, Texas Oil & Gas Association, GPTC, Nicor, Ameren Illinois and Oleksa and Associates (a pipeline industry consultant) suggested further involvement of local governments not be required. These commenters contended pipeline operators have more relevant knowledge and involvement of inexperienced entities in identifying HCAs is more likely to result in confusion than useful information. The Texas associations suggested current public awareness requirements afford sufficient involvement of local agencies.

4. Accufacts noted local governmental agencies have maps identifying locations important to public safety and suggested these maps should be used by pipeline operators in HCA determinations. Accufacts believes this could assist operators in assuring consideration of accurate, complete, and current information.

5. Northern Natural Gas reported it has a phone number and email address that local residents and agencies can use to provide input to its HCA determinations. Northern further reported no HCAs have been identified from information provided via these avenues that were not otherwise known to the company.

6. Public commenters suggested local residents and government agencies should receive more information concerning pipelines and HCAs. One commenter suggested operators should provide copies of IM plans upon request, and should provide prior notification to residents within a PIR of assessments and a subsequent report of assessment results or problems otherwise identified. This individual also suggested locations of HCAs and assessment trend results should be provided to local communities upon request. The League of Women Voters of Pennsylvania suggested distribution integrity management plans should be readily available and the public should be involved in decisions related to those plans.

7. Pipeline Safety Trust commented public review should be part of any process by which PHMSA reviews or approves of HCA identifications.

8. Wyoming County Pennsylvania Commissioners suggested stakeholder meetings and public comment periods be required as part of HCA identification. They noted local residents know their communities better than others, including expected changes that could affect HCA identification.

9. AGA and several of its member operators recommended local governments play no role in oversight of HCA determinations. They contended this would increase burden and result in inconsistencies and confusion.

10. An anonymous commenter suggested existing public awareness contacts should be used to improve HCA determinations. The commenter expressed the belief this existing structure could allow low-cost involvement of local officials in such determinations.

11. The NTSB suggested PHMSA work with states to employ oversight of pipeline IM plans based on objective metrics. The NTSB noted this would be consistent with recommendation P–11–20 resulting from its investigation of the San Bruno, CA pipeline accident.

12. Iowa Association of Municipal Utilities noted local government employees are involved when HCA determinations are made by municipal utilities and further requirements for

local involvement would be inappropriate for such operators.

Response to Question A.7 Comments

PHMSA appreciates the information provided by the commenters. PHMSA is continuing to evaluate this aspect of integrity management but has not yet reached any conclusions. PHMSA may consider this input for future action, if applicable.

A.8. Should PHMSA develop additional safety measures, including those similar to IM, for areas outside of HCAs? If so, what would they be? If so, what should the assessment schedule for non-HCAs be?

1. Pipeline operators and their associations generally agreed additional measures were not needed outside HCA. INGAA and several transmission pipeline operators suggested operators be allowed to apply the principles of ASME/ANSI B31.8S voluntarily, as needed. INGAA noted this is the concept behind its Integrity Management—Continuous Improvement (IMCI) initiative.

2. AGA and a number of its member operators noted the regulations already require implementation of preventive and mitigative measures outside of HCA for low-stress pipe (§ 192.935(d)). These requirements include using qualified personnel to conduct work that could adversely affect the integrity of the covered segment, collecting excavation damage information, and participating in one-call systems.

3. Ameren Illinois and MidAmerican commented additional measures are not needed, because existing operations & maintenance requirements already assure integrity.

4. GPTC and Nicor agreed, noting it would be inappropriate to apply IM measures outside of HCA and existing requirements are assuring an adequate level of safety.

5. Atmos contended the existing provision requiring that operators evaluate and remediate non-HCA pipeline segments when corrosion is found during an IM assessment of a covered pipeline segment (§ 192.917(e)(5)) already provides that actions be taken to assure the integrity of non-HCA pipeline segments.

6. Texas Pipeline Association and Texas Oil & Gas Association would not object to a phased expansion of IM requirements provided that required assessment intervals are scientifically based. The associations noted Texas pipelines are already subject to the broader requirements of the Texas IM rule. They commented phased implementation would assure the next-highest risks are addressed first and would allow time for IM-support resources to grow.

7. Iowa Association of Municipal Utilities commented new requirements are not needed for its members' pipelines. These lines are small-diameter, low-pressure, odorized, and already pose low risk.

8. Northern Natural Gas suggested PHMSA expand the HCA definition gradually over time rather than imposing IM requirements outside HCA. Northern commented such an approach would retain and expand the focus on areas posing the highest risk.

9. Accufacts commented repair criteria, including required response times, and reporting of anomalies should be the same in- or outside HCA, since the progression of an anomaly to failure is unrelated to whether the anomaly exists within or outside of an HCA.

10. Pipeline Safety Trust suggested non-HCA pipeline segments should be subject to a baseline of IM requirements.

11. The Commissioners of Wyoming County Pennsylvania suggested PHMSA consolidate operators' best practices and require assessment of all pipe frequently enough to realize a benefit. They commented this approach would assure a consistent level of public protection regardless of the practices of individual pipeline operators.

12. California Public Utilities Commission noted this question would be moot if method 2 for defining HCA is eliminated.

Response to Question A.8 Comments

PHMSA appreciates the information provided by the commenters. Although most industry commenters did not support expansion of integrity management requirements outside HCAs, PHMSA believes additional protections are needed for pipeline segments where people are expected within the PIR. In this NPRM, PHMSA proposes an approach that balances the need to provide additional protections for persons within the potential impact radius (PIR) of a pipeline rupture (outside of a defined HCA), and the need to prudently apply IM resources in a fashion that continues to emphasize the risk priority of HCAs. The proposed regulation would require selected aspects of IM programs (namely, integrity assessments and repair criteria) to be applicable for selected non-HCA segments defined as MCAs. An MCA would be a segment located where persons live and work and could reasonably be expected to be located within a pipeline PIR. PHMSA would propose requirements that integrity assessments be conducted, and that injurious anomalies and defects be repaired in a timely manner, using similar standards in place for HCAs. However, the other program elements of a full IM program contained in 49 CFR part 192, subpart O would not be required for MCA segments.

A.9. Should operators be required to submit to PHMSA geospatial information related to the identification of HCAs?

1. Most industry commenters, including INGAA, AGA, and numerous pipeline operators supported this proposed requirement. They noted submission of this data will be required for PHMSA to comply with the mapping provisions of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.

2. Accufacts, Alaska Department of Natural Resources, California Public Utility Commission, and one private citizen agreed, suggesting PHMSA should know where HCAs are located and that this information is important to emergency responders. CPUC also suggested operators should be required to submit this information to State regulatory authorities as well.

3. Pipeline Safety Trust also supported this proposal, adding the information should be shared with the public.

4. League of Women Voters of Pennsylvania and Accufacts also supported making maps identifying pipeline locations, including HCA, available to the public.

5. Atmos, Northern Natural Gas, Kern River, Nicor, and GPTC opposed a requirement to submit this information. They noted this is a large amount of information which is available for audits and questioned how it would be used by PHMSA and how related security issues would be addressed.

6. Ameren Illinois suggested a requirement to submit HCA locations is not needed, since location data on the entire pipeline system must already be submitted to the National Pipeline Mapping System.

7. Texas Pipeline Association, Texas Oil & Gas Association, and MidAmerican agreed that providing HCA information as part of NPMS submissions is adequate. They noted this is consistent with Section 6 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.

Response to Question A.9 Comments

PHMSA appreciates the information provided by the commenters. Most commenters supported the submittal of HCA information in geospatial format. As noted by one commenter, this is required by the Act. Although outside

the scope of this rulemaking, PHMSA is pursuing data reporting improvements by proposing revisions to its currently approved information collection for the National Pipeline Mapping System. PHMSA has published several **Federal Register** notices and held several public workshops on the proposals.

A.10. Why has the number of HCA miles declined over the years?

1. Responses to this question consisted of speculation regarding reasons why the number of HCA miles may have declined. No commenters reported having specific data to describe the reducing trend.

2. AGA suggested pipe replacement, reductions in MAOP, and use of better data could be among the many reasons for a decline in HCA mileage.

3. INGAA speculated the reduction could be a result of operators changing from method 1 to method 2 to identify HCAs and abandoning or retiring older pipelines.

4. Texas Pipeline Association, Texas Oil & Gas Association, Atmos, and a private citizen agreed a change in the method for identifying HCAs is a likely reason for the decreasing mileage trend.

5. Northern Natural Gas commented changes in land use over time result in changes in the pipeline segments identified as HCA. Northern noted it has changed from method 1 to method 2 for identifying HCA but that the change had resulted in an increase in HCA mileage rather than a decrease. Kern River also reported that its HCA mileage is increasing, citing changes in land use along the pipeline as the reason for this change.

6. GPTC and Nicor suggested operational changes and removal of pipe from service could be the cause of the observed changes.

7. Iowa Utilities Board noted reductions in pressure and other operational changes can eliminate covered pipeline segments. IUB also suggested a change from method 1 to method 2 and better analyses of potential impact circles, etc. could have resulted in decreased HCA mileage.

8. MidAmerican noted its HCA mileage has fluctuated but remains relatively constant overall. They noted periodic fluctuations result from changes in various parameters that go into identifying HCAs.

9. A private citizen suggested operators may be buying properties within potential impact circles and razing them or that new pipelines in rural areas may be replacing current pipelines.

10. An anonymous commenter suggested HCA mileage is decreasing because operators are getting better at identifying HCAs. The commenter noted operators have been doing so for 9 years.

Response to Question A.10 Comments

PHMSA appreciates the information provided by the commenters. PHMSA considered this input in its evaluation mandated by the Act.

A.11. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible.

1. Accufacts commented property damage costs reported to PHMSA following pipeline incidents appear to be understated. Accufacts noted this raises serious questions about the validity of cost-benefit analyses performed using this data.

2. Iowa Association of Municipal Utilities commented the costs to comply with IM-like requirements are not justified for small, low-pressure transmission pipelines such as those operated by its members. Significant costs to develop IM plans, evaluate remote valves, and comply with other IM requirements must be passed on to a small rate base for many municipal utilities.

3. ITT Exelis Geospatial Systems suggested HCA criteria be revised and requirements for protection of critical infrastructure and populated areas be made more prescriptive. They commented such changes would require that leak surveys be performed more frequently, providing improved safety.

4. ITT Exelis Geospatial Systems reported its leak detection systems, developed as part of research jointly sponsored with DOT and other agencies, could facilitate this testing and initial costs would be offset by longer term savings.

5. California Public Utilities Commission observed the public has indicated its desire for more prescriptive safety requirements.

Response to Question A.11 Comments

The Act requires that the Secretary of Transportation to evaluate whether integrity management requirements should be expanded beyond HCAs and whether such expansion would mitigate the need for class location requirements. The proposed rulemaking does not change the HCA definition. However, PHMSA is proposing pipeline assessment requirements in new § 192.710 for newly defined moderate consequence areas (MCAs). PHMSA is also proposing new requirements in § 192.607 for verification of pipeline material and § 192.624 for MAOP verification would also apply to MCAs. PHMSA performed a Preliminary Regulatory Impact Analysis, using the best available data and information. It is available on the docket and PHMSA invites comments on the PRIA.

B. Strengthening Requirements To Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs

Section 192.935 requires gas transmission pipeline operators to take additional measures, beyond those already required by part 192, to prevent a pipeline failure and to mitigate the consequences of a potential failure in a HCA following the completion of a risk assessment. Section 192.935(a) specifies examples of additional measures, which include, but are not limited to installing automatic Shut-off Valves or Remote Control Valves; installing computerized monitoring and leak detection systems; replacing pipe segments with pipe of heavier wall thickness; providing additional training to personnel on response procedures; conducting drills with local emergency responders; and implementing additional inspection and maintenance programs. In the ANPRM, PHMSA expressed concern that these additional measures are not explicitly required. As a result, operators may not be employing the appropriate additional measures as intended. Section 192.935(b) specifies that operators are also required to enhance their damage prevention programs and to take additional measures to protect HCA segments subject to the threat of outside force damage (non-excavation). PHMSA also noted in the ANPRM that the provisions in § 192.935 only apply to HCAs and that the expansion of the HCA definition would increase the mileage of pipelines subject to § 192.935. Further, PHMSA acknowledged the consideration of expanding preventive and mitigative measures to pipelines outside of HCAs. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic B

1. INGAA suggested PHMSA can substantially improve prevention and mitigation of accidents caused by excavation damage by facilitating full implementation of state damage prevention programs. INGAA further suggested PHMSA actively promote the use of 811 one-call programs. INGAA noted excavation damage remains the most prevalent cause of serious incidents and failure to notify is a primary cause of these incidents. Many pipeline operators supported the INGAA comments.

2. INGAA, supported by many of its pipeline operator members, noted it has a policy goal to apply integrity management principles, voluntarily, to pipelines beyond HCAs. Their goal is to address 90 percent of the population near pipelines by 2020 and 100 percent by 2030 through application of appropriate principles from ASME/ ANSI B31.8S.

3. AGA supported application of IM principles, but not assessment requirements, outside HCAs. AGA commented requiring operators to understand and address risks is a good application of IM principles. Many pipeline operators supported the AGA comments.

4. AGA commented the ANPRM incorrectly states that § 192.935 applies only to pipe within HCAs. AGA noted paragraph (d) of that section applies to low-stress pipe in Class 3 and 4 areas that is not in HCAs.

5. California Public Utilities Commission suggested pipelines installed prior to the promulgation of federal pipeline safety requirements (so-called ''pre-code'' pipe) be reassessed more frequently.

6. Alaska Natural Gas Development Authority commented Alaska's experience indicates improved pipeline design and construction requirements are needed to assure pipeline integrity. These would include stronger pipe, improved requirements for mainline valves (including spacing and remote operation), and improved corrosion control. The Authority also commented that design requirements need to accommodate likely changes in class location, noting that explosive growth in some Alaska areas has resulted in rapid changes from Class 1 to Class 3.

7. One private citizen suggested some level of assessment should be required for all pipelines.

8. Another private citizen suggested integrity management plans for densely populated areas (Class 4 and Class 5—a new class suggested by the commenter encompassing cities with population greater than 100,000) should be developed in consultation with local emergency responders. The commenter further suggested these plans should be available at the FERC environmental impact study stage and should be reviewed with local authorities.

9. Another private citizen suggested information should be shared across pipeline operators, noting this would augment the knowledge of individual companies and improve safety. Similarly, the commenter suggested PHMSA require operators to submit a list of preventive and mitigative measures that have been implemented and reports of their effectiveness. The commenter noted PHMSA should know this information but apparently does not, as indicated by questions posed in this ANPRM (particularly questions B.1 and B.2).

Comments Submitted for Questions in Topic B

B.1. What practices do gas transmission pipeline operators now use to make decisions as to whether/which additional preventive and mitigative measures are to be implemented? Are these decisions guided by any industry or consensus standards? If so, what are those industry or consensus standards?

1. Most industry commenters indicated ASME/ANSI B31.8S is a common standard used to guide decisions concerning preventive and mitigative measures. INGAA suggested enhancing this standard would be the best approach to provide additional guidance for selection and implementation of these measures. Other commenters also cited the GPTC Guide as a useful guideline. INGAA listed other standards used by pipeline operators, including:

- Common Ground Alliance Best Practices
- Pipelines and Informed Planning Alliance Recommended Practices
- API–RP 1162—Public Awareness Programs,
- API–RP 1166—Excavation Monitoring
- NACE SP0169, other associated NACE standards
- Gas Piping Technology Committee guidance materials
- RSTRENG—A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe
- INGAA Foundation Guidelines for Evaluation and Mitigation of Expanded Pipes

AGA also noted that operators are guided by their own risk assessments. Many pipeline operators supported the INGAA and AGA comments.

2. Northern Natural Gas reported it does not rely on a specific consensus standard to select preventive and mitigative measures. It relies, instead, on company subject matter experts guided by statistical analyses of their risk model.

3. Paiute and Southwest Gas reported they use an algorithm combining risk scores, threats, and the value of specific measures. Company engineers analyze the results of applying this algorithm and develop preventive and mitigative measure implementation plans.

4. An anonymous commenter noted many pipeline operators are implementing actions that could be considered preventive and mitigative measures but these actions may not be identified as such if they are implemented as part of operations and maintenance activities and not specifically included in IM plans.

5. INGAA suggested PHMSA would benefit by applying ASME/ANSI B31.8S in its IM enforcement activities.

B.2. Have any additional preventive and mitigative measures been voluntarily implemented in response to the requirements of § 192.935? How prevalent are they? Do pipeline operators typically implement specific measures across all HCAs in their pipeline system, or do they target measures at individual HCAs? How many miles of HCA are afforded additional protection by each of the measures that have been implemented? To what extent do pipeline operators implement selected measures to protect additional pipeline mileage not in HCAs?

1. INGAA reported many pipeline operators have implemented additional preventive and mitigative measures. INGAA does not keep data on this and did not provide examples. Some pipeline operators submitted examples in support of the INGAA comments. Preventive and mitigative measures cited in these examples include:

- Additional reconnaissance (after seismic events, floods, etc.);
- Concrete mats over pipelines in areas particularly susceptible to excavation damage;
- Encroachment sensors;
- Remotely operated valves;
- Removal of casings;
- Completion of CIS surveys;
- Clearing of rights-of-way;
- Derating/deactivating of pipelines;
- Relocation of pipelines;
- Increased inspection of river crossings;
- Lowering of shallow pipelines;
- Installation of additional marker posts;
- Revising marking standards for locates;
- Completing depth-of-cover surveys;
- Enhancing right-of-way patrols.

In addition, one pipeline operator reported augmented implementation of many requirements of part 192 and implementation of some requirements (*e.g.*, operator qualification) beyond their specified bounds.

2. AGA also reported many additional preventive and mitigative actions have been implemented but, again, does not keep data on them. Examples cited by AGA and its operator members included increased use of indirect inspection tools, increased patrols, and investigation of apparent instances of encroachment.

3. GPTC reported data is not collected concerning voluntary measures.

4. Texas Pipeline Association and Texas Oil & Gas Association similarly reported that they do not collect this data, and there was only limited response to a survey of their operators regarding this question. The associations reported their understanding that measures are not generally implemented system-wide.

5. California Public Utilities Commission reported some CA operators are stationing personnel at the location of excavations near transmission pipelines. CAPUC also noted California's one-call law requires a mandatory field meeting before any excavation near a transmission pipeline operating above 60 psi.

6. An anonymous commenter suggested operators avoid implementing non-required actions for fear they will lead to new requirements.

7. Industry comments indicated data is not collected concerning the extent of implementation of voluntary preventive and mitigative measures. Some measures are implemented in specific HCAs while others may be implemented more broadly across a pipeline system. The extent depends largely on the threat being addressed and its prevalence.

8. Northern Natural Gas reported it has implemented voluntary measures outside HCA, citing as examples high-visibility markers in Class 1 areas and use of LIDAR leak detection. Northern reported broad implementation of voluntary measures is more prevalent than site specific use.

9. MidAmerican reported virtually all of its transmission pipeline mileage is subject to at least one preventive and mitigative measure.

10. Paiute reported nine measures are applied to all of its 856 miles of transmission pipeline while 13 are applicable to all 27 miles of HCA.

11. Similarly, Southwest Gas has implemented nine measures on 841 miles and 13 on all 191 miles of HCA.

12. AGA reported that approximately 195,000 non-HCA miles have been assessed, generally through assessing pipe upstream and downstream of the HCA segment.

B.3. Are any additional prescriptive requirements needed to improve selection and implementation decisions? If so, what are they and why?

1. Industry commenters unanimously agreed no new prescriptive requirements are needed. INGAA pointed out selection of preventive and mitigative measures is based on criteria in consensus standards and operator judgment. INGAA contended this allows appropriate customization and results in improved safety. AGA agreed, noting operators are in the best position to decide what is needed for their pipeline systems. GPTC stated that its Guide is sufficient, and there has been no demonstrated safety need for additional requirements. Several pipeline operators suggested conducting assessments and making repairs provides the most effective safety improvement.

2. Paiute and Southwest Gas suggested a best practices workshop to share industry experience could be beneficial.

3. Accufacts suggested additional prescriptiveness is needed to guide decisions regarding remote and automatically operated valves in HCA.

4. The Alaska Department of Natural Resources would suggest signoff by a professional engineer on preventive and mitigative action decisions.

5. The NTSB recommended improved use of metrics in inspection protocols, citing their recommendations P–11–18 and 19.

6. One private citizen suggested the lack of specifically-required actions in the regulations represents a deficiency in the pipeline safety regulatory program. The commenter suggested the extent of operator judgment be limited and that state and local officials should participate in developing a list of applicable preventive and mitigative actions.

7. An anonymous commenter suggested including more examples of preventive and mitigative actions in the regulations would help guide operator consideration of appropriate actions. The commenter also suggested operators be required to update their risk analyses, and selection of preventive and mitigative actions, more frequently including after changes in their pipeline systems or the occurrence of significant events.

B.4. What measures, if any, should operators be required explicitly to implement? Should they apply to all HCAs, or is there some reasonable basis for tailoring explicit mandates to particular HCAs? Should additional preventative and mitigative measures include any or all of the following: Additional line markers (line-of-sight); depth of cover surveys; close interval surveys for cathodic protection (CP) verification; coating surveys and recoating to help maintain CP current to pipe; additional right-of-way patrols; shorter ILI run intervals; additional gas quality monitoring, sampling, and inline inspection tool runs; and improved standards for marking pipelines for operator construction and maintenance and one-calls? If so, why?

1. INGAA, supported by many of its pipeline operator members, commented prescriptive requirements are not needed. INGAA contended prescriptive requirements are neither effective nor efficient and that ASME/ANSI B31.8S and the GPTC Guide provide sufficient guidance.

2. AGA commented one-call requirements and the actions required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 are the only actions that should be required on a system-wide basis. AGA further suggested it could be appropriate to apply the additional measures required of low-pressure pipelines in § 192.935(d) to pipelines operating above 30 percent SMYS.

3. Texas Pipeline Association and Texas Oil & Gas Association recommended no new requirements be adopted applying specific preventive and mitigative actions throughout pipeline systems. The associations noted part 192 already requires application of some measures throughout pipeline systems and expressed their conclusion these already-specified measures are sufficient.

4. MidAmerican commented requiring application of specified measures throughout pipeline systems would provide a disincentive for the application of other measures which could be more appropriate.

5. The NTSB recommended requirements for leak detection in SCADA systems should be improved, citing their recommendation P–11–10.

6. California Public Utilities Commission recommended operators be required to station stand-by personnel at excavations near transmission pipelines and operator procedures should specify the actions these stand-by personnel must take. CPUC further suggested these standby activities should be a covered task under operators' personnel qualification programs.

7. Pipeline Safety Trust recommended PHMSA mandate the NTSB recommendations, noting many are similar to the specific measures suggested in this question. PST further commented operators should not be allowed sufficient latitude to render a regulation meaningless.

8. An anonymous commenter suggested the regulations should not specify particular preventive and mitigative measures but should emphasize consideration of potential accident consequences when selecting actions. The commenter noted there are too many variables to specify particular actions in regulation.

9. A private citizen suggested operators should be required to conduct drills with local responders periodically as part of their integrity management programs. The commenter noted such drills would improve coordination and would validate the ability to respond in the event of an emergency.

10. A private citizen suggested stronger enforcement is needed based on the belief that operators should already be taking many of the actions suggested in this question.

11. With respect to the specific actions suggested in this question:

a. Line-of-sight markers: National Utility Locating Contractors Association recommended line-of-sight markers be required, noting that they would reduce the instances of excavators failing to call for a locate, which the Common Ground Alliance's Damage Information Reporting Tool (DIRT) continues to indicate is a major cause of excavation damage. The Association further recommended the message on markers should be visible from all angles, noting that most current markers are only visible from two directions. The Commissioners of Wyoming County Pennsylvania, and MidAmerican suggested line-of-sight markers should be required, noting that they are a low-cost good practice for improving safety. An industry consultant disagreed, noting installation would be impractical in many areas where the sight line is obscured by crops, terrain, etc.

b. Depth of cover: MidAmerican opposed required depth of cover surveys, commenting they are not a good indicator of likely damage and such surveys are inherently inaccurate. Texas Pipeline Association and Texas Oil & Gas Association suggested compliance with depth of cover requirements over time is impractical. They noted operators do not have full control over rights of way and that owners can make changes. For example, a landowner may pave an area following grading which reduces the depth of cover. California Public Utilities Commission recommended depth of cover surveys be required wherever external corrosion direct assessment is applied and where vehicles or other loads capable of damaging the pipeline have access to the surface over the pipeline. Wyoming County Pennsylvania's Commissioners suggested depth of cover surveys be required as a good safety practice.

c. Close interval surveys: MidAmerican recommended against requiring these surveys. The company noted they are only one means of determining the adequacy of cathodic protection. The Commissioners of Wyoming County Pennsylvania recommended such surveys be required as a good safety practice.

d. Coating surveys and re-coating: MidAmerican opposed a requirement for coating surveys, noting holidays are found and repaired through in-line inspection and external direct assessment. The company further noted pipe replacement is often a superior repair to recoating. The Wyoming County Commissioner commented periodic coating surveys are a good practice and recommended that they be required.

e. Additional right of way patrols: MidAmerican and the Wyoming County Commissioners agreed increased frequency of patrols would be appropriate. MidAmerican noted patrols are a relatively low cost action that generates useful data.

f. Shorter ILI intervals: MidAmerican opposed shorter intervals, noting many lines cannot accommodate in-line inspection or more frequent runs. The Wyoming County Commissioners argued that frequent assessment is a good practice that should be required.

g. Additional gas quality monitoring: MidAmerican opposed such a requirement, arguing it would be redundant for distribution pipeline operators receiving gas from suppliers. The Wyoming County Commissioners argued frequent gas monitoring would be a good practice.

h. Improved pipeline marking standards: MidAmerican agreed implementing new marking standards would be a low cost action. Wyoming County again noted this is a good practice.

B.5. Should requirements for additional preventive and mitigative measures be established for pipeline segments not in HCAs? Should these requirements be the same as those for HCAs or should they be different? Should they apply to all pipeline segments not in HCAs or only to some? If not all, how should the pipeline segments to which new requirements apply be delineated?

1. INGAA, supported by many of its member companies, argued preventive and mitigative measures should be applied to non-HCA areas on a risk basis rather than by prescriptive requirement. INGAA commented this is a more effective and efficient means of increasing pipeline safety.

2. AGA commented codifying different requirements for non-HCA areas would likely cause confusion and extending existing IM requirements to non-HCA areas would create an enormous burden for PHMSA and states. AGA noted the NTSB has already questioned the ability of regulators to apply the existing IM inspection protocols to HCA mileage. AGA recommended one-call and the actions required by statute be the only additional measures required system-wide.

3. GPTC, Texas Pipeline Association, Texas Oil & Gas Association, and two pipeline operators opposed requirements for preventive and mitigative actions in non-HCA areas. These commenters argued it is important to allow pipeline operators the flexibility to select actions that are appropriate to their circumstances and implementing actions required arbitrarily would be expensive and ineffective.

4. Northern Natural Gas suggested PHMSA expand the HCA definition gradually over time rather than imposing IM requirements outside HCA. Northern commented such an approach would retain and expand the focus on areas posing the highest risk.

5. MidAmerican opposed additional requirements for preventive and mitigative actions, noting all pipeline is covered by other requirements in part 192 and it is better to focus enhanced requirements on areas posing highest risk.

6. AGA commented measures required in HCA should always be equal to or more stringent than measures required outside of HCA. AGA noted this is a fundamental principle of integrity management: Focusing on areas posing higher risks.

7. Ameren Illinois and an anonymous commenter suggested better enforcement and/or specificity for provisions requiring operators consider other areas of their systems when problems are discovered would be more effective than requiring preventive and mitigative measures outside HCA.

8. ITT Exelis Geospatial Systems commented requirements should be the same in- or outside HCA. They contended non-HCA areas are not monitored for leakage as often as Class 3 and 4 locations. They suggested their LIDAR system would allow effective and efficient leak surveys in all locations.

9. A public citizen recommended exposed pipe be wrapped in bright colors and protected from damage whether inside or outside of HCA. The commenter suggested analysis of data from CGA's Damage Information Reporting Tool would be an effective preventive measure.

B.6. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible.

In addition, PHMSA requests commenters to provide information and supporting data related to, among other factors, the potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.

1. Northern Natural Gas reported the additional cost of preventative and mitigative measures it employs, including instrumented aerial leakage surveys, close-interval surveys, additional mailings and additional signage, has been approximately $950,000. Northern further reported the approximate cost of conducting assessments through in-line inspection or pressure testing for all high-consequence areas every seven years is $45,000,000 and reduction of the inspection interval would increase the cost accordingly.

Response to Topic B comments

Section 5 of the Act requires that the Secretary of Transportation complete an evaluation and issue a report on whether integrity management requirements should be expanded beyond HCAs and whether such expansion would mitigate the need for class location requirements. Aspects of this topic that relate to applying a risk analysis to determine additional preventive and mitigative measures for non-HCA pipeline segments will be addressed later, pending completion of the evaluation and report. PHMSA will review the comments received on this topic and will address them in the future in light of these statutory requirements.

Section 3 of the Act requires that the Secretary of Transportation complete an evaluation and issue a report on the impact of excavation damage on pipeline safety. Aspects of this topic that relate to additional preventive and mitigative measures for damage prevention will be addressed after completion of the evaluation and report. PHMSA will review the comments received on this topic and will address them in the future in light of this evaluation and report.

Section 6 of the Act requires that the Secretary of Transportation provide guidance on public awareness and emergency response plans. Aspects of this topic that relate to additional preventive and mitigative measures for public awareness and emergency response will be further evaluated in conjunction with this statutory mandate. PHMSA will review the comments received on this topic and will address them in the future in light of this evaluation.

Two specific areas of preventive and mitigative actions addressed in the IM requirements (49 CFR 192.935) are leak detection and automatic/remote control valves. The IM rule does not require specific measures be taken to address these aspects of pipeline design and operations, but does include them among candidate preventive and mitigative measures operators should consider. Both of these topics are the subject of recommendations that the NTSB made (recommendations P–11–10 and P–11–11) following the San Bruno explosion. In response to these recommendations, PHMSA conducted a public workshop on March 27, 2012, to seek stakeholder input on these issues, and is sponsoring additional research and development to further inform PHMSA's response on these issues. Aspects of this topic that relate to leak detection and automatic/remote control valves will be addressed after completion and evaluation of the above activities. PHMSA will review the comments received on leak detection and automatic/remote control valves and will address them in the future in light of this evaluation.

PHMSA is proposing to add requirements for enhanced preventive and mitigative measures to address internal and external corrosion control. The intent of the IM rulemaking is to enhance protections for high consequence areas. PHMSA believes that enhanced requirements for internal corrosion and external corrosion control are prudent. To address internal corrosion, PHMSA is proposing specific requirements for operators to monitor gas quality and contaminants and to take actions to mitigate adverse conditions. To address external corrosion, PHMSA is proposing specific requirements for operators to monitor and confirm the effectiveness of external corrosion control through electrical interference surveys and indirect assessments, including cathodic protection surveys and coating surveys, to take actions needed to mitigate conditions that are unfavorable to effective cathodic protection, and to integrate the results of these surveys with integrity assessment and other integrity-related data. PHMSA addresses this topic in more detail in response to comments related to Topic I, Corrosion Control.

Note: Specific comments submitted for Topic B that are related to risk and integrity assessments are addressed under Topics E and G.

C. Modifying Repair Criteria

The existing integrity management regulations establish criteria for the timely repair of injurious anomalies and defects discovered in the pipe (49 CFR 192.933). These criteria apply to pipeline segments in an HCA, but not to segments outside an HCA. The ANPRM announced that PHMSA is considering amending the integrity management rule by revising the repair criteria to provide greater assurance that injurious anomalies and defects are repaired before the defect can grow to a size that leads to a leak or rupture. In addition, PHMSA is considering establishing repair criteria for pipeline segments located in areas that are not in an HCA in order to provide greater assurance that defects on non-HCA pipeline segments are repaired in a timely manner. The following are general comments received related to the topic and then comments related to the specific questions:

General Comments for Topic C

1. INGAA reported its members' commitment to apply ASME/ANSI B31.8S corrosion anomaly criteria both inside and outside of HCAs. INGAA noted that new research to refine and extend the technical bases for responding to corrosion anomalies identified primarily by ILI has been completed by Pipeline Research Council International, whose report was expected to be published in the first quarter of 2012. INGAA also reported a commitment to develop and use criteria for mitigation of dents, corrosion pitting, expanded pipe corrosion, and selective seam weld corrosion. Numerous pipeline operators supported INGAA's comments.

2. AGA suggested that ASME/ANSI B31.8S should be the basis for defining anomalies requiring remediation. Anomalies not meeting the criteria in that standard, in AGA's opinion, do not require repair. AGA further commented that risk prioritization of maintenance and anomaly response should not be regulated because operators are in the best position to know the factors influencing prioritization for apparently-similar anomalies. AGA also suggested that PHMSA review INGAA's paper ''Anomaly Response and Mitigation Outside of High Consequence Areas when Using in Line Inspection,'' dated May 30, 2010, as this paper forms the basis for current industry response outside of HCAs. Numerous pipeline operators supported AGA's comments.

3. Accufacts contended that there have been too many corrosion-caused ruptures occurring shortly after in-line

inspection runs and that this indicates the need for more prescriptive criteria for corrosion evaluation and remediation.

4. Alaska Department of Natural Resources commented that repairs should be made using permanent methods, and that clamps and similar repairs are not sufficient.

Response to General Comments for Topic C

PHMSA appreciates the information provided by the commenters. Because the current repair criteria only address corrosion metal loss as an immediate condition, PHMSA agrees that more prescriptive repair criteria are needed to address significant corrosion metal loss that does not meet the immediate repair criterion, similar to the hazardous liquid integrity management repair criteria at 49 CFR 195.452(h). In addition, other conditions that are not currently addressed in the repair criteria, such as stress corrosion cracking and selective seam weld corrosion, are addressed in ASME B31.8S and other sources, but not explicitly addressed in part 192. PHMSA is proposing to enhance the repair criteria for HCA segments and is also proposing to add specific repair criteria for pipeline in non-HCA segments. In general, PHMSA is proposing to add more immediate repair conditions and more one-year conditions for HCA segments. The additional criteria address conditions not previously addressed, such as stress corrosion cracking, and also include more specific one-year criteria for corrosion metal loss, based on the design factor for the class location in which the pipeline is located, to address corrosion metal loss that reduces the design safety factor of the pipe. PHMSA is also proposing to apply similar repair criteria in non-HCA segments, except that response times will be tiered, with longer response times for non-immediate conditions. PHMSA reviewed available industry literature, including ASME/ANSI B31.8S, in developing the proposed repair criteria. Specific aspects of the proposed rules are discussed in response to the specific questions for Topic C, below.

PHMSA has not addressed the specific procedures and techniques for performing repairs in this rulemaking, but may do so at a later date.

Comments Submitted for Questions in Topic C

C.1. Should the immediate repair criterion of failure pressure ratio *(FPR) ≤1.1 be revised to require repair at a higher threshold (i.e., additional safety margin to failure)? Should repair safety margins be the same as new construction standards? Should class location changes, where the class location has changed from Class 1 to 2, 2 to 3, or 3 to 4 without pipe replacement have repair criteria that are more stringent than other locations? Should there be a metal loss repair criterion that requires immediate or a specified time to repair regardless of its location (HCA and non-HCA)?*

1. INGAA, supported by numerous pipeline operators, commented the FPR criterion need not be changed, noting there have been no reported incidents due to the criterion being too lax. INGAA also objected to PHMSA's characterization of this issue, noting that repair criteria already exceed 1.1 FPR; the 1.1 FPR criterion in the regulations governs response to anomalies and not the criteria to which repairs must be made.

2. AGA, supported by numerous of its pipeline operator members, commented that the FPR criterion should not be changed. AGA contended that the criterion already provides a 10 percent safety margin and is based on sound engineering practices.

3. Northern Natural Gas and Kern River stated that conservatism is present in burst pressure calculations and in the measurement of anomalies (considering tool tolerance), providing a safety margin greater than 10 percent.

4. Accufacts argued against changing the FPR criterion, but suggested that PHMSA require operators to use better assumptions in their failure analyses. Accufacts suggested that the regulations should focus on preventing failures but that existing safety margins need not be increased.

5. Texas Pipeline Association, Texas Oil & Gas Association, Atmos, and MidAmerican opposed changes to this criterion. These commenters noted that experience through the baseline inspections has demonstrated the criterion is adequate and ASME/ANSI B31.8S remains a good guide for anomaly response. Atmos added that this criterion separates immediate repairs from scheduled repairs: It allows a risk-based focus on more serious anomalies but does not mean that anomalies providing more than 10 percent margin to burst pressure are never addressed.

6. California Public Utilities Commission suggested that the FPR criterion be increased to 1.25 times MAOP. CPUC noted that the 10 percent margin in the current criterion can be completely erased by the 10 percent margin to safety relief settings allowed by § 192.201.

7. INGAA commented that additional repair criteria are not needed. INGAA noted that §§ 192.485(a) and 192.713(a) already specify repair criteria applicable to pipe outside HCA. Numerous pipeline operators supported INGAA's comments.

8. AGA, supported by numerous of its pipeline operator members, suggested that safety margins for repairs need not be the same as those for new construction. AGA argued that the construction margins are intended to address potential unknowns and forces applied during construction, which are not applicable to repairs.

9. Accufacts, Northern Natural Gas, and an anonymous commenter agreed that repairs, once initiated, should meet new construction safety margins.

10. INGAA and several of its pipeline operator members argued that repair criteria should not be more stringent where class location has changed. INGAA noted that § 192.611 does not change the original design criteria for segments that have been subject to a change in class location and there is no incident experience suggesting that additional safety margin is needed in these cases.

11. Northern Natural Gas and Kern River argued against a change in repair criteria where class location has changed, noting that the likelihood of failure of an anomaly is not affected by the class location and that treatment in accordance with integrity management requirements already considers risk.

12. MidAmerican, Paiute, and Southwest Gas added that use of the factor failure pressure divided by MAOP in ASME/ANSI B31.8S already reflects any change in MAOP necessitated by a change in class location.

13. Accufacts commented that repair criteria should be commensurate with the more restrictive design criteria of higher class locations.

14. INGAA commented no new metal loss criterion is needed, noting that its members use HCA response criteria as a guide for responding to indications of metal loss outside of HCAs. Numerous pipeline operators supported INGAA's comments.

15. AGA commented any metal loss criterion should reflect current science and should be the same regardless of class location. AGA suggested that immediate response to any indication of a dent with metal loss is not needed, noting that there have been many examples of dents with metal loss not sufficient to require recalculating remaining strength. AGA also noted the external corrosion direct assessment standard requires a similar response regardless of whether an indication is in

or outside HCA. Numerous pipeline operators supported AGA's comments.

16. Accufacts encouraged PHMSA to establish a prompt-action criterion for wall loss inside or outside HCAs, suggesting the focus should be on preventing ruptures regardless of where they occur. Accufacts also cautioned PHMSA against accepting studies attempting to show that 80 percent wall loss is sometimes acceptable, and stated that continued operation with such wall loss is too risky for onshore pipelines.

Response to Question C.1 Comments

PHMSA appreciates the information provided by the commenters. The majority of comments supported no changes to the immediate repair criterion of predicted failure pressure of less than or equal to 1.1 times MAOP for HCAs, and PHMSA is not proposing to change this criterion; however, PHMSA is proposing several changes to enhance the repair criteria both for HCA segments and non-HCA segments. For immediate conditions, PHMSA proposes to add the following to the immediate repair criteria: Metal loss greater than 80% of nominal wall thickness, indication of metal-loss affecting certain types of longitudinal seams, significant stress corrosion cracking, and selective seam weld corrosion. These additional repair criteria would address specific issues or gaps with the existing criteria. The methods specified in the IM rule to calculate predicted failure pressure are explicitly not valid if metal loss exceeds 80% of wall thickness. Corrosion affecting a longitudinal seam, especially associated with seam types that are known to be susceptible to latent manufacturing defects such as the failed pipe at San Bruno, and selective seam weld corrosion are known near-term integrity threats. Stress corrosion cracking is listed in ASME B31.8S as an immediate repair condition, which is not reflected in the current IM regulations. PHMSA proposes to add requirements to address these gaps.

The current regulations include no explicit metal loss repair criteria, other than one immediate condition. The regulations direct operators to use Figure 4 in ASME B31.8S to determine non-immediate metal loss repair criteria. PHMSA now proposes to explicitly include selected metal loss repair conditions in the one-year criteria. These proposed criteria are consistent with similar criteria currently invoked in the hazardous liquid integrity management rule at 40 CFR 195.452(h). In addition, PHMSA proposes to incorporate safety factors commensurate with the class location in which the pipeline is located, to include predicted failure pressure less than or equal to 1.25 times MAOP for Class 1 locations, 1.39 times MAOP for Class 2 locations, 1.67 times MAOP for Class 3 locations, and 2.00 times MAOP for Class 4 locations in HCAs. Lastly, in response to the lessons learned from the Marshall, Michigan, rupture, PHMSA proposes to include any crack or crack-like defect that does not meet the proposed immediate criteria as a one year condition. PHMSA proposes to apply these same criteria as two-year conditions for non-HCAs.

PHMSA agrees with Accufacts' comment that the regulations should focus on preventing failures but that existing safety margins are adequate when properly applied. Therefore, the proposed rule does not propose to increase safety margins such as the design factor. PHMSA maintains that the proposed changes discussed above provide a tiered, risk-based approach to metal loss repair criteria and by requiring predicted failure pressures as a function of class locations does not compound safety margins. Counter to INGAA's and AGA's comments that repair criteria should not be more stringent where class location has changed, PHMSA believes the tiered approach to metal loss repair criteria, which is a function of class location, provides a logical framework to address the risk presented by these types of pipeline anomalies.

In conjunction with enhanced repair criteria, PHMSA is proposing specific new regulations to require that operators properly analyze uncertainties and other factors that could lead to non-conservative predictions of failure pressure, and time remaining to failure, when evaluating ILI anomaly indications. PHMSA specifically is proposing that operators must analyze specific known sources of uncertainty regarding ILI tool performance, anomaly interactions, and other sources of uncertainty when determining if an anomaly meets any repair criterion.

C.2. Should anomalous conditions in non-HCA pipeline segments qualify as repair conditions subject to the IM repair schedules? If so, which ones? What projected costs and benefits would result from this requirement?

1. INGAA suggested that new criteria are not needed, commenting that operators generally treat non-HCA anomalies in a manner similar to HCA anomalies, except for response time. INGAA stated that industry costs to address non-HCA anomalies should be nominal unless immediate response is required because this is consistent with current operator practice, which INGAA stated is to apply ASME/ANSI B31.8S response criteria for anomalies both inside and outside HCAs.

2. Texas Pipeline Association and Texas Oil & Gas Association commented that differing repair criteria, if any, should be based upon the population at risk, since there is no valid engineering basis for treating anomalies differently depending on location.

3. Atmos and Northern Natural Gas suggested that non-HCA anomalies should be treated like HCA anomalies, although additional schedule flexibility should be allowed. Northern reported that it applies HCA metal loss criteria everywhere because it is prudent, although response time differs for non-HCA anomalies. Northern reported that it has expended approximately $7.7 million on anomaly repairs, $7 million of which was outside an HCA.

4. Kern River agreed that IM schedules are too stringent to apply everywhere and providing schedule flexibility will reduce costs.

5. MidAmerican disagreed with the suggestion that non-HCA and HCA anomalies be treated alike. MidAmerican commented that it is illogical to back off from focusing sooner on anomalies that pose greater risks.

6. California Public Utilities Commission commented that all locations identified by the method described in paragraph 1 in the definition of HCA in § 192.903 should be subject to HCA repair criteria.

7. Pipeline Safety Trust, Accufacts, and NAPSR commented that the same repair criteria and response schedule should apply regardless of where an anomaly is located. These commenters contended that there is no logical justification for different treatment, that any risk to the pipeline and public safety should be resolved, and that a pipeline accident anywhere is seen by the public as a failure to exercise adequate control of pipeline safety. NAPSR, in particular, suggested that all anomalies should be repaired immediately, regardless of where they are located.

8. Iowa Utilities Board, Iowa Association of Municipal Utilities, GPTC, Nicor, Ameren Illinois and an anonymous commenter contended that HCA repair criteria should not be applied outside HCAs. These commenters noted that there has been no demonstrated safety need for new criteria, that non-HCA anomalies are adequately addressed under existing operations and maintenance requirements, and that the cost to apply HCA repair criteria everywhere is not justified. IAMU particularly noted that

existing requirements are adequate for small, low-pressure transmission pipelines such as those operated by its members.

9. A private citizen supported application of HCA repair criteria in non-HCA areas, particularly where there are ''receptors,'' which the commenter defines as ''something which needs to be protected.''

Response to Question C.2 Comments

PHMSA appreciates the information provided by the commenters. PHMSA proposes to modify the general requirement for repair of pipelines to include immediate repair condition criteria, one-year conditions, and monitored conditions. The definition of these conditions would be the same as the existing definitions for covered segments (*i.e.,* HCA segments) in the IM rule; however, PHMSA proposes that those conditions that must be repaired within one year in a HCA segment would be required to be repaired within two years in a non-HCA segment. Defects that meet any of the immediate criteria are considered to be near-term threats to pipeline integrity and would be required to be repaired immediately regardless of location.

PHMSA believes that establishing these non-HCA segment repair conditions are important because, even though they are not within the defined high consequence locations, they could be located in populated areas and are not without consequence. For example, as reported by operators in the 2011 annual reports, while there are approximately 20,000 miles of gas transmission pipe in HCA segments, there are approximately 65,000 miles of pipe in Class 2, 3, and 4 populated areas. PHMSA believes it is prudent and appropriate to include criteria to assure the timely repair of injurious pipeline defects in non-HCA segments. These changes will ensure the prompt remediation of anomalous conditions on all gas pipeline segments while allowing operators to allocate their resources to high consequence areas on a higher priority basis.

C.3. Should PHMSA consider a risk tiering—where the conditions in the HCA areas would be addressed first, followed by the conditions in the non-HCA areas? How should PHMSA evaluate and measure risk in this context, and what risk factors should be considered?

1. INGAA, and many pipeline operators, opposed the suggested tiering. They commented that anomalies meeting response criteria should be addressed in an appropriate time frame whether inside or outside HCAs.

2. AGA, supported by many of its operator members, suggested that PHMSA not adopt any risk tiering beyond the current requirements to focus first on HCA anomalies. AGA noted that outside factors, *e.g.,* permitting, affect the timing and the sequence of repairs.

3. Texas Pipeline Association and Texas Oil & Gas Association commented that PHMSA should allow risk tiering system-wide, not just in differentiating between responses in and outside HCA. The associations suggested that this could be an improvement to requirements addressing anomalies. At the same time, they noted the description in the ANPRM is sketchy and requested PHMSA propose specific requirements for comment.

4. Iowa Association of Municipal Utilities commented that no new requirements are needed, and that the existing requirements are sufficient for the small, low-stress transmission pipelines operated by its members.

5. Atmos commented that the risk tiering concept is confusing and stated that it was considered and rejected when the initial IM rules were promulgated.

6. Northern Natural Gas commented that allowing a longer response time for anomalies outside HCA would be a form of risk tiering. The company reported it has incorporated this practice in its procedures.

7. Accufacts agreed that a focus on HCA anomalies is needed but cautioned against ignoring anomalies outside HCAs. Accufacts noted the progression of an anomaly to failure does not depend on whether or not it is located in an HCA.

Response to Question C.3 Comments

PHMSA appreciates the information provided by the commenters. Current regulations do not prescribe response timeframes for anomalies outside HCAs. As stated by Northern Natural Gas, allowing a longer response time for anomalies outside HCAs (compared to response times for anomalies inside HCAs) would be a form of risk-tiering. PHMSA is proposing such an approach, which would establish three timeframes for performing repairs in non-HCA areas: Immediate repair conditions, 2-year repair conditions, and monitored conditions. These changes will ensure the prompt remediation of anomalous conditions on all gas pipeline segments, while allowing operators to allocate their resources to those areas that present a higher risk.

C.4. What should be the repair schedules for anomalous conditions discovered in non-HCA pipeline segments through the integrity assessment or information analysis? Would a shortened repair schedule significantly reduce risk? Should repair schedules for anomalous conditions in HCAs be the same as or different from those in non-HCAs?

1. INGAA commented that repair schedules outside HCAs should be similar to those in HCAs but should allow for more scheduling latitude. This comment was supported by comments received from many of its operator members. They also noted that adding requirements to repair non-HCA anomalies would significantly increase the number of required repairs and that an inappropriate requirement for rapid response would dilute the focus on risk-significant repairs. INGAA suggested that repair schedules should be more a function of anomaly growth rates than location along the pipeline. INGAA further suggested that inappropriately rapid response schedules would increase risk; experience shows that most anomalies that have been found and repaired are old, do not require a rapid response, and that mandating rapid response to such anomalies would necessarily dilute other safety activities.

2. Texas Pipeline Association and Texas Oil & Gas Association expressed doubt that significant risk reduction would result from shortened repair schedules, given the logistics and related work involved in repairs.

3. GPTC, Nicor, and an anonymous commenter objected to applying HCA repair criteria outside HCAs. They believe that the costs for such an approach are not justified and non-HCA anomalies are appropriately dealt with under operations and maintenance requirements and procedures.

4. Ameren Illinois, Paiute, and Southwest Gas agreed that prescriptive repair schedules are not needed outside HCAs. They expressed a belief that operators must have scheduling flexibility to accommodate the needs of their operations.

5. MidAmerican suggested that immediate repair criteria be applied both in HCAs and outside HCAs, but that other criteria be limited to HCAs.

6. Northern Natural Gas suggested that PHMSA should require operators to determine response schedules for non-HCA anomalies as part of this rulemaking.

7. Iowa Association of Municipal Utilities commented that the existing requirements are sufficient for the small, low-stress transmission pipelines operated by its members.

8. California Public Utilities Commission commented that all method

1 HCA locations should be subject to HCA repair criteria.

9. MidAmerican, Paiute, and Southwest Gas commented that shortened response schedules will not reduce risk. These operators suggested that response times should be based on risk rather than being established arbitrarily.

Response to Question C.4 Comments

PHMSA appreciates the information provided by the commenters. PHMSA believes repair schedules outside HCAs should be similar to those in HCAs but should allow for more scheduling latitude. PHMSA proposes to establish three timeframes for remediating defects in non-HCA areas: Immediate repair conditions, 2-year repair conditions (rather than one-year for HCAs), and monitored conditions. These changes will ensure the prompt remediation of anomalous conditions on all gas pipeline segments, commensurate with risk, while allowing operators to allocate their resources to those areas that present a higher risk.

C.5. Have ILI tool capability advances resulted in a need to update the ''dent with metal loss'' repair criteria?

1. INGAA commented that ILI tool capabilities have improved to the point where it is appropriate to revise the dent-with-metal loss criterion. This comment was supported by comments received from many of its operator members. INGAA suggested that Section 851.4(f) of ASME/ANSI B31.8 provides appropriate guidance in this area.

2. AGA suggested that it would be appropriate to eliminate the immediate response criterion for ''dent with metal loss.'' This comment was supported by comments received from many of its operator members. They commented that industry experience has shown that many dents do not require immediate repair.

3. Texas Pipeline Association, Texas Oil & Gas Association, MidAmerican, Paiute, Southwest Gas, and Atmos supported revising this criterion. These commenters noted that improvements in ILI allow better distinction between a gouge and corrosion wall loss. MidAmerican further commented that there are problems with implementing § 192.933 as written.

4. Northern Natural Gas stated that it would support treating these anomalies as mechanical damage, and suggested that this would simplify the regulations.

5. Ameren Illinois suggested further study of this proposal taking into account current ILI technology.

6. Accufacts and an anonymous commenter opposed changes to this criterion. These commenters suggested that ILI is still not adequate to determine reliably the time to failure of this compound threat.

7. GPTC and Nicor suggested that PHMSA consider updating the Dent Study technical report [35] that discusses reliability and application of ILI.

Response to Question C.5 Comments

PHMSA appreciates the information provided by the commenters. PHMSA is not proposing to update the dent-with-metal-loss criterion at this time. PHMSA will continue to evaluate this criterion, including consideration of additional research to better define the repair criteria for this specific type of defect.

C.6. How do operators currently treat assessment tool uncertainties when comparing assessment results to repair criteria? Should PHMSA adopt explicit voluntary standards to account for the known accuracy of in-line inspection tools when comparing in-line inspection tool data with the repair criteria? Should PHMSA develop voluntary assessment standards or prescribe ILI assessment standards including wall loss detection threshold depth detection, probability of detection, and sizing accuracy standards that are consistent for all ILI vendors and operators? Should PHMSA prescribe methods for validation of ILI tool performance such as validation excavations, analysis of as-found versus as-predicted defect dimensions? Should PHMSA prescribe appropriate assessment methods for pipeline integrity threats?

1. INGAA, supported by many of its member companies, reported that operators use many methods to accommodate ILI uncertainties, not simply adding tool tolerance to results. INGAA suggested API–1163, In-line Inspection Systems Qualification Standard, as an appropriate guide. INGAA noted this standard is non-prescriptive; INGAA expressed its belief prescriptive standards would stifle innovation. INGAA also reported that ASME has plans to update its standard on ''Gas Transmission and Distribution Piping Systems,'' ASME/ANSI B31.8S, regarding treatment of uncertainties based on the results of Pipeline Research Council International (PRCI) research that was underway at the time comments were submitted.

2. AGA and a number of pipeline operators suggested that tool tolerances should be added to ILI results.

3. Texas Pipeline Association, Texas Oil & Gas Association, and Atmos reported their understanding that most operators follow ASME/ANSI B31.8S as a guide.

4. Northern Natural Gas and Kern River expressed their conclusion that PHMSA's Gas Integrity Management Program Frequently Asked Question FAQ–68 provides sufficient guidance on the treatment of uncertainties (FAQs can be viewed at *http://primis.phmsa.dot.gov/gasimp/faqs.htm*). They noted that technology is developing rapidly in this area, which they imply is a reason not to impose prescriptive requirements.

5. Texas Pipeline Association and Texas Oil & Gas Association agreed that prescriptive requirements should not be imposed, because the rapidly-developing technology would soon render them obsolete.

6. GPTC, Nicor, MidAmerican, and Atmos argued that prescriptive methods for validating tool performance are not an appropriate subject for regulation.

7. Ameren Illinois commented that it sees no technical justification for establishing requirements in this area.

8. Accufacts suggested that PHMSA specify minimum standards for ILI validation, including specifying a required number of digs. Alaska Department of Natural Resources and California Public Utilities Commission took a similar stance, all arguing that standards assure public confidence and consistency of results.

9. A private citizen commented that voluntary standards are not sufficient because they cannot be enforced.

10. An anonymous commenter recommended against adopting requirements for treatment of inaccuracies. The commenter opined that operators are doing better in this area, contending that smaller operators, in particular, needed time to learn. The commenter suggested that specific rules would set many operators back.

11. INGAA and many of its pipeline operators commented that incorporating standards into part 192 that compete with industry standards would be counterproductive. INGAA noted that API–1163, API–579–1, Fitness-for-Service, and ASNT ILI–PQ, In-Line Inspection Personnel Qualification and Certification Standard, are already in wide use and contended specifying standards in the regulations would stifle further development.

12. GPTC and Nicor agreed with INGAA, noting that the regulatory approval process cannot keep up with technological development.

13. Northern Natural Gas recommended that PHMSA not adopt standards for addressing ILI inaccuracies, contending the many

[35] Baker and Kiefner & Associates, ''Dent Study Technical Report,'' (November 2004, OPS TTO Number 10, available at *http://primis.phmsa.dot.gov/gasimp/techreports.htm*).

different tools currently in use would make this impractical.

14. MidAmerican reported its belief that operators have sufficient incentive to work with ILI vendors to assure appropriate validation of ILI results.

15. Paiute and Southwest Gas argued against adoption of regulatory standards to treat ILI uncertainties, noting that this subject is already addressed in ASME/ANSI B31.8S.

16. AGA, supported by a number of its member companies, suggested that PHMSA should not prescribe IM methods, noting that operators have demonstrated the ability to conduct assessments without them.

17. Accufacts, Alaska Natural Gas Development Authority, and California Public Utilities Commission argued for requirements prescribing assessment methods for various threats. These commenters suggested that such requirements would be a bridge to better risk management strategies and contended that there is currently an over-reliance on direct assessment.

Response to Question C.6 Comments

PHMSA appreciates the information provided by the commenters. The majority of comments do not support adopting explicit standards or analytical methodologies to account for the known accuracy of in-line inspection tools. PHMSA concurs that prescriptive rules to account for the accuracy of in-line inspection tools is not practical, however it is beneficial to all to clarify PHMSA's expectations with respect to current performance-based regulations in this area which specify that internal inspection may be used to identify and evaluate potential pipeline threats. Therefore, PHMSA proposes to add detailed performance-based rule language to require that operators using ILI must explicitly consider uncertainties in reported results (including tool tolerance, anomaly findings, and unity chart plots or equivalent for determining uncertainties) in identifying anomalies. While ASME/ANSI B31.8S discusses uncertainties, PHMSA believes it will improve the visibility and emphasis on this important issue to explicitly address uncertainties in the rule text.

C.7. Should PHMSA adopt standards for conducting in-line inspections using "smart pigs," the qualification of persons interpreting in-line inspection data, the review of ILI results including the integration of other data sources in interpreting ILI results, and/or the quality and accuracy of in-line inspection tool performance, to gain a greater level of assurance that injurious pipeline defects are discovered? Should these standards be voluntary or adopted as requirements?

1. AGA and its pipeline operator members argued against the adoption of standards. AGA commented that voluntary use has proven to be sufficient and expressed its position that consensus standards should not be adopted into regulations until widespread experience has been gained with their use. AGA contended that premature adoption would stifle technological innovation.

2. INGAA and many of its members commented that PHMSA's process for review and adoption of standards must be streamlined if existing consensus standards are incorporated into regulations. Such improvements, INGAA contended, would assure that standard improvements are adopted without delay.

3. An anonymous commenter, GPTC, and Nicor cited similar concerns in suggesting that standards not be adopted into regulations, contending that the rulemaking process cannot keep up with technological change.

4. Texas Pipeline Association and Texas Oil & Gas Association objected to the adoption of ILI standards in regulations, contending that voluntary use is more appropriate.

5. MidAmerican commented that operator qualification requirements should be applied to ILI, as this would provide higher assurance of defect discovery. Beyond this, however, MidAmerican contended that the use of consensus standards should remain voluntary, as this allows the operator to select those standards most appropriate to its circumstances.

6. Paiute and Southwest Gas objected to the incorporation of ILI standards into regulations. The companies expressed a belief that there is no technical basis for doing so. They commented that the question, as posed in the ANPRM, implies that anomalies are not now being found and contended that there is no evidence to support this implication.

7. A private citizen, Thomas Lael, and Alaska Department of Natural Resources commented that PHMSA should require operators to meet specified standards. Mr. Lael referred to an incident that occurred following a pipeline assessment conducted in Ohio in 2011; Mr. Lael contended that the reasons the incident cause was not identified by the assessment are unknown to the public.

8. Pipeline Safety Trust commented that PHMSA should assure assessment tools are capable and are used properly.

9. The NTSB recommended that PHMSA require all pipelines to be made piggable, giving priority to older lines, citing their recommendation P–11–17.

Response to Question C.7 Comments

PHMSA appreciates the information provided by the commenters. The majority of industry comments do not support the incorporation of ILI standards into regulations. However, based on the information presented below, PHMSA has concluded that it is prudent to propose incorporating available consensus ILI standards into the regulations. The current pipeline safety regulations for integrity management of segments in HCAs contained in 49 CFR 192.921 and 192.937 require that operators assess the material condition of pipelines in certain circumstances and allow use of in-line inspection tools for these assessments. PHMSA proposes to incorporate similar requirements for non-HCA pipe segments in § 192.710. Operators are required to follow the requirements of ASME/ANSI B31.8S in selecting the appropriate ILI tools. However, ASME B31.8S provides only limited guidance for conducting ILI assessments. At the time the integrity management rules were promulgated, there was no consensus industry standard that addressed performance of ILI. Three related standards have since been published: API STD 1163–2005, NACE SP0102–2010, and ANSI/ASNT ILI–PQ–2010. API–1163 serves as an umbrella document to be used with and complement the NACE and ASNT standards. These three standards have enabled service providers and pipeline operators to provide processes that will qualify the equipment, people, processes, and software utilized in the in-line inspection industry. The incorporation of these standards into pipeline safety regulations developed through best practices of the industry based on the experience of numerous operators will promote high quality and more consistent assessment practices. Therefore, PHMSA is proposing to incorporate these industry standards into the regulations to provide clearer guidance for conducting integrity assessments with in-line inspection. PHMSA will continue to evaluate the need for additional guidance for conducting integrity assessments.

C.8. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements*

pursuant to the commenter's suggestions.

- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

D. Improving the Collection, Validation, and Integration of Pipeline Data

The ANPRM requested comments regarding whether more prescriptive requirements for collecting, validating, integrating and reporting pipeline data are necessary. The current IM regulations require that gas transmission pipeline operators gather and integrate existing data and information concerning their entire pipeline that could be relevant to pipeline segments in HCAs (§ 192.917(b)). Operators are then required to use this information in a risk assessment of the HCA segments (§ 192.917(c)) that must subsequently be used to determine whether additional preventive and mitigative measures are needed (§ 192.935) and to define the intervals at which IM reassessments must be performed (§ 192.939). Operators' risk analyses and conclusions can only be as good as the information used to perform the analyses. On August 30, 2011, after the ANPRM was issued, the NTSB adopted its report on the gas pipeline accident that occurred on September 9, 2010, in San Bruno, California. Results from the NTSB investigation indicate that the pipeline operator's records regarding the physical attributes of the pipe segments involved in the incident were erroneous. NTSB recommendation P–11–19 recommended that PHMSA require IM programs be assessed to assure that they are based on clear and meaningful metrics. In addition, Section 23 of the Act requires verification to ensure that records accurately reflect the physical and operational characteristics of pipelines. PHMSA issued an Advisory Bulletin (76 FR 1504; January 10, 2011) on this issue. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic D

1. INGAA reported that it is presently working on data integration guidelines. INGAA cautioned that requirements in this area can be very costly, since they often necessitate redesign of existing data management systems.

2. AGA commented that no records requirements would have prevented the San Bruno accident, and stated that verifying records does not assure completeness, as unknown parameters remain unknown.

3. A private citizen suggested that PHMSA should require operators to identify segments where they lack knowledge of critical parameters. The commenter suggested that this could facilitate emergency communications and help prioritize pipe replacement programs.

Response to General Comments for Topic D

PHMSA appreciates the information provided by the commenters. PHMSA is proposing to clarify requirements for collecting, validating, and integrating data. The current rule invokes ASME/ANSI B31.8S requirements for data collection and integration. To provide greater visibility and emphasis on this important aspect of integrity management, PHMSA is proposing to place these requirements in the rule text, rather than incorporating ASME/ANSI B31.8S by reference. The proposed requirements clarify PHMSA's expectations regarding the minimum list of data an operator must collect, and also includes performance-based language that requires the operator to validate data it will use to make integrity-related decisions, and require operators to integrate all such data in a way that improves the analysis. The proposed rule would also require operators to use reliable, objective data to the maximum extent practical. To the degree that subjective data from subject matter experts must be used, PHMSA proposes to require that an operator's program include specific integrity assessment and findings data for the threat features to compensate for subject matter expert (SME) bias. The importance of these aspects of integrity management was emphasized by both the NTSB (Recommendation P–11–19) and Congress (The Act, Section 11(a)(4)).

Comments Submitted for Questions in Topic D

D.1. What practices are now used to acquire, integrate and validate data (e.g., review of mill inspection reports, hydrostatic tests reports, pipe leaks and rupture reports) concerning pipelines? Are practices in place, such as excavations of the pipeline, to validate data?

1. INGAA reported that its members have completed a concerted effort to validate pipeline historical records pursuant to PHMSA Advisory Bulletin 11–01 (issued January 10, 2011).

2. Texas Pipeline Association and Texas Oil & Gas Association commented that there is no great benefit to be gained from adding a verification requirement for historical data to the regulations. The associations believe that most operators will correct their records when they become aware of errors regardless of how the erroneous information is discovered. The associations suggested that there could be value in validating databases against original records, since an underlying problem of the San Bruno accident was errors in transferring original records into a database.

3. Ameren Illinois reported that it collects data on exposed pipe in accordance with §§ 192.459 and 192.475.

4. Northern Natural Gas and Kern River reported that their primary integration tool is integrity alignment sheets, which show the class location, profile, aerial photography, alignment and structure data, in-line inspection results, other integrity data, *i.e.,* close-interval survey or pressure test results and pipe, coating and appurtenance data. Data is validated as opportunities arise.

5. Paiute and Southwest Gas reported that they confirm the location and properties of its pipeline as opportunities arise; more data are collected as assessments are conducted.

6. California Public Utilities Commission suggested that operators be explicitly required to obtain all historical records and that there be an officer statement that a thorough search for all records has been conducted.

7. A private citizen commented on the lack of some historical data, implying that operators should be required to validate their knowledge of older pipelines.

8. An anonymous commenter stated that older data is typically not validated.

9. INGAA and AGA reported that pipeline operators take advantage of exposed pipe to collect and validate data on in-service pipelines. This includes excavations for ILI validation, those conducted as part of direct assessment, and removed or replaced pipelines. A number of pipeline operators provided comments supporting the comments of each association.

10. GPTC and Nicor suggested that excavations not be required for the sole purpose of validating data, contending that the risks posed by such a requirement would outweigh any benefit obtained.

11. MidAmerican reported that it validates information when pipeline is excavated and through its routine practices.

Response to Question D.1 Comments

PHMSA appreciates the information provided by the commenters. See response to question D.4.

D.2. Do operators typically collect data when the pipeline is exposed for maintenance or other reasons to validate information in their records? If discrepancies are found, are investigations conducted to determine the extent of record errors? Should these actions be required, especially for HCA segments?

1. AGA, Paiute, and Southwest Gas reported that operators use exposed pipe as an opportunity to collect information. AGA further suggested, however, that PHMSA should not draft a rule governing these practices. AGA contended the circumstances of pipe exposures vary too much to be addressed by a regulatory requirement. AGA expressed its conclusion that the requirements in § 192.605(b)(3) provide adequate guidance and that section 23 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 provides additional guidance. AGA noted that operators investigate identified inaccuracies and errors. A number of other pipeline operators provided comments supporting AGA's comments.

2. Texas Pipeline Association, Texas Oil & Gas Association, Atmos, MidAmerican, and Ameren Illinois reported that operators typically collect information on pipe type and condition, but not on historical information and pipe specifications. They commented that collecting this information would require additional testing and pose operational impacts.

3. Iowa Utilities Board and Iowa Association of Municipal Utilities commented that any new requirement should be limited to collecting readily obtainable data, principally that which can be determined visually. They suggested that the data elements in ANPRM questions D.1 and D.3 go beyond what can readily be observed or obtained and it would be impractical to require this data to be collected during pipe exposures.

4. California Public Utilities Commission commented that any new requirements to collect data during pipe exposures should address all instances of exposure rather than be limited to HCAs, noting that non-HCA segments can become HCA segments due to changes in land use near the pipeline.

5. Thomas Lael and Alaska Department of Natural Resources commented that operators should be required to collect specific data during pipe exposures. These commenters contended that not all operators currently collect available data during pipe exposures.

6. MidAmerican, Paiute, and Southwest Gas commented that no new requirements are needed because the requirements in part 192 and guidance in ASME/ANSI B31.8S are sufficient.

7. An anonymous commenter suggested that operators be required to collect data if they do not have enough information to analyze the risks of the pipeline segment.

Response to Question D.2 Comments

PHMSA appreciates the information provided by the commenters. The expanded rule language does not impose new requirements for collecting specific data during pipe exposures, but the response to question D.4 discusses proposed changes to collection and validation practices to improve data integration and risk assessment practices.

D.3. Do operators try to verify data on pipe, pipe seam type, pipe mechanical and chemical properties, mill inspection reports, hydrostatic tests reports, coating type and condition, pipe leaks and ruptures, and operations and maintenance (O&M) records on a periodic basis? Are practices in place to validate data, such as excavation and in situ examinations of the pipeline? If so, what are these practices?

1. AGA, GPTC, Nicor, Paiute, and Southwest Gas reported that operators do try to verify information but that operator practices are too numerous to list in response to this general question. They contended that the requirements for external corrosion control in § 192.459 and for internal corrosion control in § 192.475 and the guidance in Advisory Bulletin 11–01 are sufficient and no new requirements are needed. A number of other pipeline operators provided comments supporting AGA's comments.

2. INGAA, supported by many of its pipeline operator members, commented that there are limited, if any, methods to determine accurately mechanical properties of pipe that is *in situ.* INGAA's comments listed a number of methods that can be used to obtain approximate values for some pipe characteristics, such as steel hardness and yield strength.

3. Texas Pipeline Association and Texas Oil & Gas Association commented that operators do not validate mill data after initial construction.

4. Ameren Illinois reported that data review and correction is a normal part of the business of pipeline operation. Ameren commented that additional work in this area is likely to result from Advisory Bulletin 11–01.

5. Northern Natural Gas reported that data correction occurs when a discrepancy is identified. Northern also noted that it has added data to its risk model over time, principally related to determination of the potential consequences of a pipeline accident.

6. MidAmerican commented that operators validate pipeline information periodically.

7. California Public Utilities Commission reported that California pipeline operators have begun validating pipeline data since the San Bruno accident. CPUC commented that operators should determine pipeline specifications for all exposed facilities and use them to validate their records.

8. Paiute and Southwest Gas reported that it is their practice to obtain pipeline data before an integrity management excavation and then to validate that information in the field.

9. MidAmerican reported that it uses a geospatial database as its principal tool for collecting and validating pipeline information.

10. An anonymous commenter suggested that pipeline operators do not routinely collect information to validate their databases during pipeline excavations.

Response to Question D.3 Comments

PHMSA appreciates the information provided by the commenters. See response to question D.4.

D.4. Should PHMSA make current requirements more prescriptive so operators will strengthen their collection and validation practices necessary to implement significantly improved data integration and risk assessment practices?

1. INGAA, GPTC, Nicor, Ameren Illinois, MidAmerican, Paiute and Southwest Gas commented that additional prescriptive requirements are not needed. These commenters suggested that Advisory Bulletin ADB–11–01, subpart O of part 192, and ASME/ANSI B31.8S are sufficient to govern these practices. INGAA added requirements for data validation during excavations could introduce workplace hazards that would outweigh any benefit to be gained. In the event PHMSA proceeds to propose new requirements, INGAA requested they be limited to a reasonable process and allow assumptions to be made to fill information gaps, suggesting this would be a more cost-effective approach than

rigorous requirements to collect and validate all information. A number of other pipeline operators provided comments supporting INGAA's comments.

2. AGA, supported by a number of its pipeline operator members, commented that there is no evidence to support a need for more prescriptive requirements leading to better data collection or validation and, therefore, no such requirements are needed.

3. Pipeline Safety Trust, NAPSR, California Public Utilities Commission, and Commissioners of Wyoming County, Pennsylvania, commented that requirements for data collection, validation, and use should be more prescriptive. These commenters noted that the investigation of the San Bruno accident identified at least one pipeline operator was not doing an adequate job of data validation. They noted that NTSB recommendations P–11–18 and P–11–19 apply to this topic. NAPSR specifically requested that new requirements specify precise inspection criteria.

4. Texas Pipeline Association and Texas Oil & Gas Association suggested that there is no value in periodic validation of pipeline data and new requirements are not needed in this area. Northern Natural Gas agreed, noting that pipeline data does not change over time, and relevant data that is subject to change, is that data needed to evaluate the consequences of potential pipeline accidents.

5. Accufacts commented that more specific criteria, including minimum data requirements, are needed for record retention. Accufacts noted that integrity management is data-based and that too many operators claim that data is lost or cannot be found.

6. Alaska Department of Natural Resources suggested that data integration should be required in interpreting ILI results.

7. An anonymous commenter suggested that specific requirements are not needed in this area, contending that most data has been validated through normal operator practices.

8. A private citizen suggested that PHMSA require pipeline operators to post all records for access by state and local government officials, PHMSA, and the media. The commenter suggested such a ''sunshine'' provision would improve recordkeeping, even if no one ever examines the posted records.

Response to Question D.4 Comments

PHMSA appreciates the information provided by the commenters in response to questions D.1 through D.4. Commenters disagreed on the need and benefit of making current requirements more prescriptive so operators will strengthen their collection and validation practices. PHMSA believes enhancing regulations in this area is an important element of good integrity management practices. On July 21, 2011, in response to the San Bruno incident, PHMSA sponsored a public workshop on risk assessment and related data analysis and recordkeeping issues to seek input from stakeholders. Based in part on the input received at this workshop, and the information submitted in response to the ANPRM, PHMSA proposes to clarify the performance-based requirements for collecting, validating, and integrating pipeline data by adding specificity to the data integration language, establishing a number of pipeline attributes that must be included in these analyses, explicitly requiring that operators integrate analyzed information, and ensuring data is reliable. The rule also requires operators to use validated, objective data to the maximum extent practical. PHMSA also understands that objective sources such as as—built drawings, alignment sheets, material specifications, and design, construction, inspection, testing, maintenance, manufacturer, or other related documents are not always available or obtainable. To the degree that subjective data from subject matter experts must be used, PHMSA proposes to require that an operator's program include specific features to compensate for subject matter expert bias. PHMSA believes that these proposed changes would not impose new requirements or more prescriptive requirements, but clarifies the intent of the regulation. However, PHMSA requests public comment on whether and the extent to which this proposal may change behavior.

D.5. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

E. Making Requirements Related to the Nature and Application of Risk Models More Prescriptive

The ANPRM requested comments regarding whether requirements related to the nature and application of risk models should be made more prescriptive to improve the usefulness of these analyses in controlling risks from pipelines. Current regulations require that gas transmission pipeline operators perform risk analyses of their pipelines and use these analyses to make certain decisions to assure the integrity of their pipeline and to enhance protection against the consequences of potential incidents. The regulations do not prescribe the type of risk analysis nor do they impose any requirements regarding its breadth and scope, other than requiring that it consider the entire pipeline. PHMSA's experience in inspecting operator compliance with IM requirements has identified that most pipeline operators use a relative index-model approach to performing their risk assessments and that there is a wide range in scope and quality of the resulting analyses. It is not clear that all of the observed risk analyses can support robust decision-making and management of the pipeline risk. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic E

1. INGAA and Chevron commented that continuing the performance-based regulatory approach, exemplified by integrity management, is critically important to pipeline safety. They suggested that prescriptive management systems are task oriented, do not adjust easily to new information or knowledge, inhibit innovation, and could thwart safety improvements. A number of other pipeline operators provided comments supporting INGAA's comments.

2. Accufacts commented that risk management approaches permitted in IM need additional prescriptive measures to clarify strengths and weaknesses and to assure compliance. Public perception resulting from the number of serious incidents is that current risk analysis and risk management approaches are not sufficient. The impression is that risk management is being used to justify unwise lowest cost decisions rather than being used as a tool to avoid failure. Accufacts further suggested that interactive threats need to be addressed by prescriptive requirements in safety

regulations because operators may be under the illusion that some of the more serious threats are stable after almost 10 years of IM regulation.

3. Oleksa and Associates suggested that it would be statistically more valid for many (perhaps most) operators for PHMSA to perform continual evaluation and assessment using established performance measures along with data submitted by operators on annual, incident, and safety-related condition reports, and then to promulgate more prescriptive regulations resulting from that assessment. Oleksa suggested that it may be time to re-evaluate the overall concept of integrity management to determine whether it makes sense for each operator to make assessments that might be more valid if made on a national level. Oleksa also stated that there should be a concerted effort in promulgating any new regulations towards making the regulations simple enough so that they can be understood relatively easily.

4. TransCanada commented that PHMSA's IM regulations should provide explicit metrics for operators to demonstrate safety decision processes without restricting the opportunity to use more accurate and advanced methods. TransCanada said that any efforts to make risk models more prescriptive should focus on process elements while providing operators the flexibility to build processes which recognize the unique characteristics of their pipeline systems. The company also opined that issuing more detailed guidelines on specific integrity management plan elements would enhance the current, performance-based approach and generate additional benefits that the public and operators desire.

5. Dominion East Ohio Gas opposed making requirements for risk models more prescriptive. Like INGAA, they that noted prescriptive management systems are task oriented and do not adjust easily to new information or knowledge. They inhibit innovation and could thwart safety improvements.

6. NAPSR strongly urged PHMSA to make the nature and application of risk models more prescriptive. NAPSR commented that PHMSA has not provided any data that supports the theory that risk modeling provides a stronger safety environment and contended that, in fact, the opposite may be occurring.

7. A private citizen suggested that PHMSA correlate the quality of an operator's risk model with the number of enforcement actions against that operator.

8. A private citizen suggested that risk analysis requirements should remain flexible, commenting that prescribed methods or requirements could mask operator-specific issues.

Response to General Comments for Topic E

PHMSA appreciates the information provided by the commenters. PHMSA agrees that prescriptive rules for risk assessments are not appropriate because one-size-fits-all regulations would not be effective for such a diverse industry. However, PHMSA does believe that operator risk models and risk assessments should have substantially improved since the initial framework programs established nearly 10 years ago. While simple index or relative (qualitative) ranking models were useful to prioritize HCA segments for purposes of scheduling integrity baseline assessments, those models have limited utility to perform the analyses needed to better understand pipeline risks, better understand failure mechanisms (especially for interacting threats), or to identify effective preventive and mitigative measures. PHMSA is proposing to further clarify its expectations for this aspect of the performance-based regulations to further improve pipeline safety. On July 21, 2011, PHMSA sponsored a public workshop on risk assessment to seek input from stakeholders. PHMSA has evaluated the input it received at this workshop. PHMSA proposes to clarify the risk assessment aspects of the IM rule to explicitly articulate functional requirements and to assure that risk assessments are adequate to: (1) Evaluate the effects of interacting threats, (2) determine intervals for continual integrity reassessments, (3) determine additional preventive and mitigative measures needed, (4) analyze how a potential failure could affect HCAs, including the consequences of the entire worst-case incident scenario from initial failure to incident termination, (5) identify the contribution to risk of each risk factor, or each unique combination of risk factors that interact or simultaneously contribute to risk at a common location, (6) account and compensate for uncertainties in the model and the data used in the risk assessment, and (7) evaluate predicted risk reduction associated with preventive and mitigative measures. In addition, in response to NTSB recommendation P–11–18, PHMSA proposes to require that operators validate their risk models in light of incident, leak, and failure history and other historical information. PHMSA also proposes to expand the list of example preventive and mitigative measures to include the following items: establish and implement adequate operations and maintenance processes that could affect safety; establish and deploy adequate resources for successful execution of activities, processes, and systems associated with operations, maintenance, preventive measures, mitigative measures, and managing pipeline integrity; and correct the root cause of past incidents to prevent recurrence.

In response to Oleksa's comments, PHMSA is addressing performance measures outside of this rulemaking. Performance measures will be addressed separately in response to NTSB safety recommendations P–11–18 and P–11–19.

Comments Submitted for Questions in Topic E

E.1. Should PHMSA either strengthen requirements on the functions risk models must perform or mandate use of a particular risk model for pipeline risk analyses? If so, how and which model?

1. INGAA, AGA, and many pipeline operators reported that they do not believe there is a pipeline safety benefit for PHMSA to ''strengthen'' or revise the requirements on functions that risk models must perform or in mandating the use of specific risk models. These commenters noted that there is a tremendous amount of diversity in the pipeline systems of individual operators and operators must have the flexibility to select the risk model that best supports their systems.

2. GPTC commented that there is no 'one-size-fits-all' risk model. GPTC further commented PHMSA has offered no data supporting the need to strengthen requirements or mandate a particular risk model.

3. Kern River noted that differences exist between pipeline operators on how much detail is needed in their risk assessment models. The specific factors and required risk model complexity will differ for each pipeline company based on its active threats, the preventive and mitigative measures employed, its data acquisition methods and the amount of required data.

4. MidAmerican commented that no change is needed to requirements concerning risk models. MidAmerican noted that ASME/ANSI B31.8S provides extremely detailed requirements in this area, and suggested that operators should have the freedom to choose the risk model best suited to their operation. Northern Natural Gas agreed, noting that there are large differences within the industry on the complexity of the risk assessment models used based on the

pipeline age and configuration, threats, and data available.

5. Paiute and Southwest Gas opposed more restrictive requirements for risk modeling. They noted that operators have a decade of experience working with IM and therefore, should have the flexibility to choose the risk model that best suits their system.

6. Accufacts commented that this is an area that needs more prescriptive requirements. Accufacts questioned whether the current approach of reliance on risk modeling is even appropriate. They stated that there appears to be a disconnect between the use of risk models and risk analysis with pipeline operation and the ability of regulators to apply and enforce the approach.

7. TransCanada noted that mandating the use of a specific risk model may result in a more uniform approach across the industry, but may also force operators to abandon their existing risk models, including the improvements made to them based on 10 years of integrity management experience. This would not appear to advance risk modeling and might even be counterproductive.

8. WKM Consultancy commented that mandating a specific risk assessment model would not be a beneficial addition to regulations. Such a mandate would stifle creativity and require extensive definitions and documentation of that methodology. A mandated model would introduce a prescriptive element with substantial ''overhead'' related to the maintenance of the model's documentation by the regulators. They suggested that a better solution would be to develop guidelines of essential ingredients necessary in any pipeline risk assessment.

9. An anonymous commenter opposed requiring the use of a specific risk model, suggesting that operators should use models with which they are comfortable. The commenter did suggest that PHMSA strengthen requirements concerning the use of risk models for purposes other than risk-ranking segments, expressing a belief that most operators are using their models only for that purpose.

10. California Public Utilities Commission recommended that PHMSA require statistical data be maintained and used to support the weightings assigned by risk models to various threats.

Response to Question E.1 Comments

PHMSA appreciates the information provided by the commenters. A large number of comments do not support adding a requirement for a specific risk assessment model or for strengthening or revising the required functions that risk models must perform. PHMSA agrees that prescribing the use of particular risk assessment models is not appropriate for such a diverse industry, and notes that relative index models have been successfully used to rank pipelines to prioritize baseline assessments. However, PHMSA believes that the integrity management rule anticipates that operators would continually improve their risk assessment processes and that there are specific risk assessment attributes related to the nature and application of risk models that need clarification. Such attributes and shortcomings were discussed at the ''Improving Pipeline Risk Assessments and Recordkeeping'' workshop with stakeholders, held on July 21, 2011.

PHMSA proposes to articulate clear functional requirements, in performance-based terms, for risk assessment methods used by operators. While PHMSA does not propose to prescribe the specific risk assessment model operators must use, PHMSA does propose to clarify the characteristics of a mature risk assessment program. These include: (1) Identifying risk drivers; (2) evaluating interactive threats; (3) assuring the use of traceable and verifiable information and data; (4) accounting for uncertainties in the risk model and the data used; (5) incorporating a root cause analysis of past incidents; (6) validating the risk model in light of incident, leak and failure history and other historical information; (7) using the risk assessment to establish criteria for acceptable risk levels; and (8) determining what additional preventive and mitigative measures are needed to achieve risk reduction goals. PHMSA proposes to clarify that the risk assessment method selected by the operator must be capable of successfully performing these functions.

E.2. It is PHMSA's understanding that existing risk models used by pipeline operators generally evaluate the relative risk of different segments of the operator's pipeline. PHMSA is seeking comment on whether or not that is an accurate understanding. Are relative index models sufficiently robust to support the decisions now required by the regulation (e.g., evaluation of candidate preventive and mitigative measures, and evaluation of interacting threats)?

1. Industry commenters, including INGAA, AGA, Texas Pipeline Association, Texas Oil & Gas Association, WKM Consultancy, and many pipeline operators reported that PHMSA's understanding is correct and that risk models in use generally *evaluate the relative risk of different segments of the operator's pipeline.* AGA noted that operators have selected and implemented the risk models that allowed them to prioritize the covered segments for the baseline assessment and subsequent reassessments and that this complied with the Pipeline Safety Improvement Act of 2002.

2. AGA, supported by a number of its pipeline operator members, commented that risk models currently in use are sufficiently robust. Ameren Illinois and GPTC expressed a similar belief.

3. INGAA, supported by some of its members, noted that there is room for improvement in the current practices of risk modeling. INGAA reported that the industry has established committees to identify advancements in risk modeling.

4. WKM Consultancy commented that the more robust of the relative risk index techniques are often capable of fulfilling some aspects of IM risk management requirements such as prioritization, but that other aspects of the risk management requirements are not well supported by relative risk assessments. They suggested that some risk assessment models in current use could benefit from application of more robust and modern techniques.

5. Kern River commented that a relative risk model is sufficiently robust to support decisions on preventive and mitigative measures and assessment intervals.

6. MidAmerican reported that its risk model complies with ASME/ANSI B31.8S and is sufficiently robust to support decisions that are not specifically related to assessments. MidAmerican further stated that its risk model produces results consistent with its subject matter expert assessments of relative risk.

7. Paiute and Southwest Gas reported their conclusion that their risk models are robust and support the process of evaluation and selection of preventive and mitigative measures.

8. Texas Pipeline Association and Texas Oil & Gas Association noted that all sources of information relative to the integrity of a transmission pipeline segment and the identified risk should be used in the selection of preventive and mitigative measures. Atmos agreed, noting that preventive and mitigative measures for a given pipeline segment are based on the identified threats.

9. A private citizen suggested that consideration of system-wide high risk (*e.g.,* urban areas) should be required, contending relative risk is not good enough when an entire system poses high risks.

Response to Question E.2 Comments

PHMSA appreciates the information provided by the commenters. Although a large number of comments contend risk models currently in use are sufficiently robust, PHMSA believes that there are specific risk assessment attributes not found in many of the simple index or relative risk models currently in use. The July 21, 2011, workshop on ''Improving Pipeline Risk Assessments and Recordkeeping'' identified several shortcomings in risk assessments conducted using qualitative, index, or relative risk methodologies, and PHMSA is proposing to clarify requirements to address these issues including the need for better or more prescriptive guidance to address data gaps, data integration, uncertainty, interacting threats, risk management, and quantitative approaches instead of subjective or qualitative approaches. The proposed regulation would require operators to conduct risk assessments that effectively analyze the identified threats and potential consequences of an incident for each HCA segment. Additionally, the proposed regulation would require the risk assessment to include evaluation of the effects of interacting threats, including those threats and anomalous conditions not previously evaluated. It should be further noted that the intent of the original IM rule is that any risk assessment would consider system-wide risk.

E.3. How, if at all, are existing models used to inform executive management of existing risks?

1. INGAA commented that operators should develop internal communication plans and they should follow Section 10.3 of ASME/ANSI B31.8S in doing so. AGA similarly noted that the methods used to disseminate results of the risk evaluation to executive management are operator specific and detailed in the operator's integrity management plan. A number of pipeline operators provided comments supporting both INGAA's and AGA's comments.

2. Texas Pipeline Association and Texas Oil & Gas Association noted that the results of risk modeling are usually used in conjunction with assessment results to inform executive management of actions required beyond normal repair, additional preventive and mitigative measures, discussion of high risk pipelines, and progress in meeting assessment goals.

3. WKM Consultancy commented that operators are obliged to communicate all aspects of integrity management to higher level managers at regular intervals. They noted that all prudent operators are very interested in risk management and results of risk modeling are usually a centerpiece of discussion and decision-making.

4. Ameren Illinois reported that its IM plan provides for informing executive management of existing risks.

5. Atmos reported that it provides executive management with periodic updates on the status of its integrity management program. During these updates, Atmos' executive management reviews baseline assessment plans, assessment results, anomalies discovered and mitigated, anomalies discovered and scheduled for repair, leading causes of anomalies, and preventive and mitigative actions taken.

6. Kern River noted that it provides its executive management with reports describing integrity management program activities and results and that the company engages the use of the risk model as an input to financial planning and maintenance planning. MidAmerican also reported that risk scores are used to support capital, operating and maintenance expenditures to executive management.

7. Northern Natural Gas reported that it provides executive management with reports describing integrity management program activities and results. Its executive management is engaged in the process and the use of the risk model to prioritize projects.

8. Paiute and Southwest Gas reported that integrity management activities are discussed with executive management quarterly.

9. An anonymous commenter suggested that operators generally do not use risk models to inform executives, because they would have to explain the models in order to do so.

Response to Question E.3 Comments

PHMSA appreciates the information provided by the commenters. PHMSA understands that internal company processes for communication with executive management are specific to each company. To strengthen the application of risk assessment, PHMSA is proposing to clarify requirements by providing more specific and detailed examples of the kinds of preventive and mitigative measures operators should consider. The proposed rulemaking would include the following specific examples of preventive and mitigative measures that operators should consider: Establish and implement adequate operations and maintenance processes; establish and deploy adequate resources for successful execution of activities, processes, and systems associated with operations, maintenance, preventive measures, mitigative measures, and managing pipeline integrity; and correct the root cause of past incidents to prevent recurrence. The last item necessarily requires a robust root cause analysis that identifies underlying programmatic or policy issues that create or facilitate conditions or circumstances that ultimately lead to pipeline failures.

E.4. Can existing risk models be used to understand major contributors to segment risk and support decisions regarding how to manage these contributors? If so, how?

1. INGAA and many of its pipeline operator members commented that existing models can and do provide an understanding of segment risk through threat identification, performing ''what if'' analyses, and identifying preventive and mitigative measures that will reduce risk.

2. AGA and GPTC noted that existing models selected by operators are sufficiently robust to allow the integration of large volumes of data and information to achieve a comprehensive overall risk evaluation for their systems. These risk models allow an operator to understand the specific threats associated with each pipeline segment and the preventive and mitigative measures that would be most appropriate. A number of pipeline operators provided comments supporting AGA's comments.

3. WKM Consultancy opined that currently used risk assessment models generally can significantly improve the ability to manage risks. They noted that a formal risk assessment provides the structure to increase understanding, reduce subjectivity, and ensure that important considerations are not overlooked.

4. Atmos reported that its model can be used to generate a report listing the significant variables contributing to a relatively higher risk factor score, and that if a contributing variable can be controlled, the risk model can support further actions to control the variable.

5. Ameren Illinois reported that it uses a robust risk model that can integrate various risk factors in order to evaluate its system.

6. Kern River and Northern Natural Gas commented that existing risk models can be used to understand major contributors to segment risk and support decisions regarding how to manage these contributors. By identifying threat drivers in the risk results and analyzing the data used by the model, integrity management personnel are able to reduce risk through preventive and mitigative measures, improvements in data quality, and shorter reassessment intervals.

7. MidAmerican reported that its risk model is used to understand major contributors to risk and to support decisions regarding how to manage those contributors.

8. Paiute and Southwest Gas reported that they conduct a review of threat-specific indices to identify the major contributors to risk for each threat.

9. Texas Pipeline Association and Texas Oil & Gas Association noted that risk modeling can be used to generate reports listing the significant variables contributing to high risk scores.

10. An anonymous commenter noted that risk models can serve these functions and some operators use them in this way. The commenter opined that most operators ''aren't there yet,'' and that operators who use models for this purpose have more enthusiasm for integrity management and more executive management support.

Response to Question E.4 Comments

PHMSA appreciates the information provided by the commenters. The majority of the comments suggest that current risk models provide an adequate understanding of major contributors to risk. PHMSA believes it is prudent to clarify the required attributes of risk assessment in this area and proposes to include performance-based language to assure that risk assessments adequately identify the contribution to risk of each risk factor, or each unique combination of risk factors that interact or simultaneously contribute to risk at a common location.

E.5. How can risk models currently used by pipeline operators be improved to assure usefulness for these purposes?

1. INGAA noted that continuous improvement is required, and that industry is working on improvements to ASME/ANSI B31.8S. AGA similarly noted that risk models are periodically improved by operators by integrating new data and the results of integrity assessments. A number of pipeline operators provided comments supporting INGAA's and AGA's comments.

2. GPTC commented that new data and information are received on an ongoing basis. This new data, and results of integrity assessments, are reviewed, integrated, and added to risk models periodically.

3. WKM Consultancy suggested that a limited amount of standardization would be appropriate. They opined that this would ensure that all risk assessments contain, at a minimum, a short list of essential ingredients. For example, all assessments should produce a profile showing changes in risk along a pipeline route.

4. Ameren Illinois reported that its risk model allows for integration of information for continuous improvement.

5. Atmos commented that there is the potential for the risk model process to handle unknown data in a more useful manner. Atmos suggested that a higher risk score with ''known'' data attributes should be considered more relevant for decisions on preventive and mitigative measures than a similar score derived from ''unknown'' data attributes.

6. Kern River suggested that industry-wide research into failure probabilities and effectiveness of preventive and mitigative measures would facilitate more rigorous quantitative models. Kern River noted that vendors are continuously improving risk models.

7. MidAmerican suggested that risk models could be improved with better tracking, recording, and retrieval of assessment results. With feedback and information sharing, refining coefficients within the model will produce more accurate risk results.

8. Northern Natural Gas reported that its risk assessment process is improved every year and that its risk model vendor is heavily involved with the company in understanding how the risk results are used.

9. Paiute and Southwest Gas suggested that risk models will be improved as additional information is gained through an assessment cycle and that this continuous improvement process will then repeat through subsequent assessment cycles.

10. Texas Pipeline Association and Texas Oil & Gas Association observed that there is no 'one size fits all' solution to this issue.

Response to Question E.5 Comments

PHMSA appreciates the information provided by the commenters. The comments speak in general terms about incremental improvement of existing index-type or qualitative relative risk models. PHMSA believes that such models, while appropriate and useful for limited purposes such as ranking segments to prioritize baseline assessments, fall far short of the type of model needed to fully execute a mature integrity management program. PHMSA proposes to clearly articulate the requirements for validation of the risk assessment and proposes to clarify that an operator must ensure validity of the methods used to conduct the risk assessment in light of incident, leak, and failure history and other historical information. Additionally, the proposed rule would require that validation must: (1) Ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents as determined by root cause analysis or other means; and (2) include analysis of the factors used to characterize both the probability of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity.

E.6. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

F. Strengthening Requirements for Applying Knowledge Gained Through the IM Program

The ANPRM requested comments regarding strengthening requirements related to operators' use of insights gained from implementation of an IM program. IM assessments provide information about the condition of the pipeline. Identified anomalies that exceed criteria in § 192.933 must be remediated immediately (§ 192.933(d)(1)) or within one year (§ 192.933(d)(2)) or must be monitored on future assessments (§ 192.933(d)(3)). Operators are also expected to apply knowledge gained through these assessments to assure the integrity of their entire pipeline as part of its threat identification and risk analysis process in accordance with § 192.917.

Section 192.917(e)(5) explicitly requires that operators must evaluate other portions of their pipeline if an assessment identifies corrosion requiring repair under the criteria of § 192.933. The operator must ''evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics.''

Section 192.917 also requires that operators conduct risk assessments that follow American Society of Mechanical Engineers/American National Standards Institute (ASME/ANSI) B31.8S, Section

5, and use these analyses to prioritize segments for assessment, and to determine what preventive and mitigative measures are needed for segments in HCAs. Section 5.4 of ASME/ANSI B31.8S states that ''risk assessment methods should be used in conjunction with knowledgeable, experienced personnel . . . that regularly review the data input, assumptions, and results of the risk assessments.'' That section further states, ''an integral part of the risk assessment process is the incorporation of additional data elements or changes to facility data,'' and requires that operators ''incorporate the risk assessment process into existing field reporting, engineering, and facility mapping processes'' to facilitate such updates. Neither part 192 nor ASME/ANSI B31.8S specifies a frequency at which pipeline risk analyses must be reviewed and updated; instead, this is considered to be a continuous, ongoing process. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comment for Topic F

1. MidAmerican suggested that application of knowledge gained through integrity management should not be treated any differently than any other information gained from work on or surveillance of the pipeline. MidAmerican considers this to be adequately addressed by § 192.613.

Response

PHMSA continues to believe that there are many important integrity management requirements related to insights gained from implementation of the IM program beyond those covered by the continuing surveillance requirements of § 192.613. Integrity management assessments provide information about the condition of the pipeline and operators are expected to apply the knowledge gained through these assessments to assure the integrity of their entire pipeline. PHMSA believes that the knowledge gained through IM assessments should be integrated into the risk assessment process, which is not required by § 192.613.

Comments Submitted for Questions in Topic F

F.1. What practices do operators use to comply with § 192.917(e)(5)?

1. INGAA and a number of pipeline operators noted that operators use available information and field knowledge to comply with this requirement.

2. AGA, supported by a number of its member companies, reported that operator practices are too distinct and varied to list. AGA stated that § 192.917(e)(5) is prescriptive enough and no new requirements are needed.

3. GPTC and Nicor cited NACE SP0169 and NACE RP0177 as examples of standards that can be used to guide compliance with § 192.917(e)(5).

4. Texas Pipeline Association and Texas Oil & Gas Association commented that operators use cathodic protection surveys and/or spot checks to determine whether failure is likely.

5. Northern Natural Gas reported that it takes the actions specified in § 192.917(e)(5) and includes consideration of incidents and safety related conditions.

6. Kern River, Paiute, and Southwest Gas stated that they use root cause evaluations of incidents to comply with § 192.917(e)(5).

Response to Question F.1 Comments

PHMSA appreciates the information provided by the commenters. The comments provide little information related to specific operator practices for compliance with § 192.917(e)(5). PHMSA is not proposing to amend § 192.917(e)(5) at this time; however, PHMSA proposes to clarify requirements in § 192.917(b) to ensure that the data gathering and integration process includes an analysis of both the HCA segments and similar non-HCA segments and integrates information about pipeline attributes and other relevant information, including data gathered through integrity assessments.

F.2. How many times has a review of other portions of a pipeline in accordance with § 192.917(e)(5) resulted in investigation and/or repair of pipeline segments other than the location on which corrosion requiring repair was initially identified?

1. Based on a limited response by their members to a survey, Texas Pipeline Association and Texas Oil & Gas Association reported that repair of corrosion beyond the initially-identified anomaly is rare.

2. Ameren Illinois reported that it has experienced two instances in which it repaired other segments after identifying corrosion on a covered pipeline segment.

3. MidAmerican reported that it has experienced a few instances of corrosion where coating was damaged during installation of a vent, and some at air-to-soil interfaces.

4. Northern Natural Gas has experienced no instances in which other pipeline segments required repair. Northern added that corrosion wall loss requiring repair is, itself, rare.

5. Paiute and Southwest Gas reported that they had not identified any immediate repair corrosion conditions.

Response to Question F.2 Comments

PHMSA appreciates the information provided by the commenters. See the response to question F.1.

F.3. Do pipeline operators assure that their risk assessments are updated as additional knowledge is gained, including results of IM assessments? If so, how? How is data integration used and how often is it updated? Is data integration used on alignment maps and layered in such a way that technical reviews can identify integrity-related problems and threat interactions? How often should aerial photography and patrol information be updated for IM assessments? If the commenter proposes a time period for updating, what is the basis for this recommendation?

1. INGAA and several pipeline operators reported that operators update risk analyses whenever new information is obtained and particularly after unexpected events.

2. AGA, GPTC, Nicor, Kern River, and TransCanada commented that risk analyses are updated at least annually.

3. Northern Natural Gas reported that its procedures provide for updating to include assessment results and changes in environmental factors.

4. Paiute and Southwest Gas reported that risk model updating is a continuous process. Rankings are updated at 18- to 24-month intervals. Ameren Illinois and Atmos similarly reported that updating is an ongoing activity.

5. Texas Pipeline Association and Texas Oil & Gas Association commented that most operators have dedicated teams to perform risk model updates.

6. Alaska Department of Natural Resources commented that risk models should be reviewed whenever significant operational or environmental changes occur. AKDNR contended that risk models are not valid if there are significant changes in these areas.

7. NAPSR reported its conclusion that risk models should be updated after every O&M activity or any finding that a required activity was not performed.

8. INGAA and a number of pipeline operators reported that data is updated using a common spatial reference system, *e.g.,* maps or tables, and the frequency of data integration varies by operator.

9. AGA, supported by a number of its member companies, reported that data integration does not always involve use of geospatial tools.

10. Atmos reported that it uses internal teams of subject matter experts for data integration and that its maps are not layered for technical data use.

11. Northern Natural Gas, Paiute, and Southwest Gas stated that they perform integration on alignment sheets based on integrity management summaries and subject matter expert reviews.

12. Texas Pipeline Association and Texas Oil & Gas Association reported that many pipeline operators are migrating to GIS systems.

13. INGAA and many pipeline operators commented that information from aerial photography should be updated annually. They noted that this would be consistent with the frequency of reviewing HCA designations and operator budgeting and contended that more frequent updates would not increase risk model accuracy. INGAA suggested that other information, including information related to external events, should be updated based on the nature and severity of experienced events.

14. AGA, Paiute, and Southwest Gas noted that not all operators use aerial photography and expressed their belief that such use should not be required. AGA noted that there are many tools, including routine patrols, to gather data about the pipeline environment. A number of member pipeline operators supported AGA's comments.

15. Northern Natural Gas reported that it updates information periodically, but with no set frequency. Northern noted that some areas are stable while change can occur rapidly in others.

16. Texas Pipeline Association and Texas Oil & Gas Association recommended annual updates as a minimum. The associations noted that this recognizes the time required to produce/acquire assessment data.

Response to Question F.3 Comments

PHMSA appreciates the information provided by the commenters. After review of the comments, PHMSA agrees that annual updates are desirable and many operators perform full updates, or partial data updates (such as updating aerial photos), annually. Some pipeline segments may be in rapidly changing, dynamic environments, while others may remain static for years. PHMSA also agrees that prescriptive requirements to perform a full risk assessment annually are not necessary and potentially burdensome, especially for very small operators, whose systems and conditions do not change often. PHMSA is satisfied that the current requirement, which contains a performance based requirement to update risk assessments as frequently as needed to assure the integrity of each HCA segment is adequate, if properly implemented, and is not proposing a prescribed frequency at this time. However, PHMSA proposes to clarify requirements in §§ 192.917 and 192.937(b) to ensure the continual process of evaluation and assessment is based on an updated and effective data integration and risk assessment process as specified in § 192.917.

F.4. Should the regulations specify a maximum period in which pipeline risk assessments must be reviewed and validated as current and accurate? If so, why?

1. INGAA and numerous pipeline operators recommended that reviews be annual, as suggested in PHMSA's Gas Integrity Management Program Frequently Asked Question FAQ–234, arguing that this is practical and sufficient (FAQs can be viewed at *http://primis.phmsa.dot.gov/gasimp/faqs.htm*).

2. AGA, GPTC, and a number of other pipeline operators commented that no maximum period should be specified for review of risk assessments. These commenters argued that no one-size-fits-all interval would be appropriate and expressed their conclusion that the current requirements in § 192.937 are adequate.

3. California Public Utilities Commission recommended that reviews be required annually, at intervals not to exceed 15 months, consistent with other requirements within part 192.

4. An anonymous commenter suggested that a specified review period would be counterproductive, arguing that most operators would simply default to the required interval, even if more frequent reviews were appropriate.

Response to Question F.4 Comments

PHMSA appreciates the information provided by the commenters. See PHMSA response to comments related to Question F.3.

F.5. Are there any additional requirements PHMSA should consider to assure that knowledge gained through IM programs is appropriately applied to improve safety of pipeline systems?

1. INGAA and many pipeline operators opined that no new requirements are needed in this area. They noted that prescriptive requirements often become out of date as technology improves.

2. AGA and numerous pipeline operators agreed that no new requirements are needed, noting that existing regulations and sharing of information through industry groups is sufficient.

3. Texas Pipeline Association and Texas Oil & Gas Association opined that existing requirements are adequate.

4. Accufacts suggested that requirements should be more prescriptive concerning threat evaluation and interactive threats, as this is the heart of integrity management.

5. An anonymous commenter suggested that new requirements be established governing assessments conducted by pressure testing. The commenter opined that the requirements in subpart J are inadequate and represent an ''easy out'' for some operators.

Response to Question F.5 Comments

PHMSA appreciates the information provided by the commenters. While PHMSA believes that explicit requirements should be included to address interactive threats, PHMSA also believes that prescriptive rules for how an operator must evaluate interactive threats are not practical. Therefore, PHMSA proposes to clarify performance-based requirements to include an evaluation of the effects of interacting threats and for the continual process of evaluation and assessment to include interacting threats in identification of threats specific to each HCA segment. Comments on integrity assessment methods are addressed in Topic G.

F.6. What do operators require for data integration to improve the safety of pipeline systems in HCAs? What is needed for data integration into pipeline knowledge databases? Do operators include a robust database that includes: Pipe diameter, wall thickness, grade, and seam type; pipe coating; girth weld coating; maximum operating pressure (MOP); HCAs; hydrostatic test pressure including any known test failures; casings; any in-service ruptures or leaks; ILI surveys including high resolution—magnetic flux leakage (HR–MFL), HR geometry/caliper tools; close interval surveys; depth of cover surveys; rectifier readings; test point survey readings; alternating current/direct current (AC/DC) interference surveys; pipe coating surveys; pipe coating and anomaly evaluations from pipe excavations; SCC excavations and findings; and pipe exposures from encroachments?

1. INGAA, supported by a number of pipeline operators, commented that experience and information gained from a variety of sources, including GIS data, corrosion data, ILI data/results, work management activities, SCADA, encroachments, leaks etc., is utilized in data integration. INGAA reported that operators have made major investments

in database applications to meet changing organizational and regulatory requirements and to manage increasing volumes of data effectively. Tools generally are available for integrating data into pipeline knowledge databases. For integration purposes, the database must contain adequate metadata elements such that dates, if important, and location and length attributes are maintained. Currently-available systems support these needs. INGAA expressed concern over use of the term ''robust database,'' since this could be construed to mean that all applicable data must be maintained in a common database or other venue which does not meet the particular needs of the operator. INGAA reported that it has an active Integrity Management—Continuous Improvement (IMCI) team addressing improvement in these processes and management systems.

2. AGA, GPTC, and a number of pipeline operators commented that a prescriptive requirement would be inappropriate because there is too much variability among operators and their risk assessment methods. AGA expressed its conclusion that there is no single methodology that incorporates the wide variety of pipeline information used by operators.

3. MidAmerican suggested that an operator needs a robust computer model to integrate diverse data dynamically into one table with one set stationing.

4. Kern River reported that it uses extensive GIS and cathodic protection databases for these purposes.

5. An anonymous commenter recommended that PHMSA require knowledge of cathodic protection current level, amount, and direction of current flow. The commenter opined that this information is not now generally collected, and that it would allow for early detection of coating failures and CP interferences.

Response to Question F.6 Comments

PHMSA appreciates the information provided by the commenters. An integral part of applying information from the IM Program to the risk assessment and other analyses is the collection, validation, and integration of pipeline data. PHMSA proposes to clarify the data integration language in the requirements by repealing the reference to ASME/ANSI B31.8S and including requirements associated with data integration directly in the rule text: (1) Establishing a number of pipeline attributes that must be included in these analyses, (2) clarifying that operators must integrate analyzed information, and (3) ensuring that data are verified and validated.

F.7. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

G. Strengthening Requirements on the Selection and Use of Assessment Methods

The existing IM regulations require that baseline and periodic assessments of pipeline segments in an HCA be performed using one of four methods:

(1) In-line inspection;

(2) Pressure test in accordance with subpart J;

(3) Direct assessment to address the threats of external and internal corrosion and SCC; or

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe.

Operators must notify PHMSA in advance if they plan to use ''other technology.'' Operators must apply one or more methods, depending on the threats to which the HCA segment is susceptible. The ANPRM requested comments related to the applicability, selection, and use of each assessment method, existing consensus standards and requirements, and the potential need to strengthen the requirements. The ANPRM then listed questions for consideration and comment. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic G

1. INGAA, supported by a number of its pipeline operator members, noted that they are committed to work with technology providers and researchers to improve the integrity management assessment capabilities of its members. Further, INGAA members are sharing their experiences with applying these new and improved assessment methods to specific threats. INGAA opined that a great advantage of the integrity management structure, as opposed to a prescriptive regulatory regime, is the creation of an environment conducive to technological development, innovation and improved knowledge.

2. Accufacts suggested that a more prescriptive regulation is needed clarifying the applicability and limitations of direct assessment. Accufacts is concerned that operators are selecting direct assessment due to a cost bias while ignoring that it cannot be used for all threats and should not be used on some pipeline segments.

3. Chevron commented that PHMSA should continue to allow operators to select and use the most effective method to assess each pipeline segment.

4. NAPSR recommended that PHMSA implement a regulatory change that requires both ILI and pressure testing for all transmission pipelines and requires a reduction in MAOP until either the ILI or the pressure tests are performed.

5. MidAmerican, a gas distribution company, noted that many of its transmission pipelines are short, small diameter lines that cannot be pigged.

6. Dominion East Ohio suggested that PHMSA should be funding more research leading to the development of assessment tools, particularly smart tools, to increase the number of assessment options available rather than limiting the tools that can be used.

7. A public citizen commented that pipe with unknown or uncertain specifications should be subject to the most stringent testing requirements.

8. Two public citizens addressed required assessment intervals. One suggested that all pipe that puts the public at significant risk should be tested, by hydro testing or some other means, at approximately ten-year intervals. Another commenter recommended that assessments be required more frequently in densely populated areas.

9. PST opined that the need to ask the questions in this section makes clear that PHMSA's current level of oversight and review of IM planning and implementation is inadequate, and calls into question the value of many IM programs, particularly those relying to any extent on direct assessment methods. PST recommended that the regulations be significantly strengthened to require PHMSA's review and administration approval of any IM program.

Response

PHMSA appreciates the information provided by the commenters. PHMSA agrees that pipeline operators should be able to select the best assessment

method applicable for its pipelines and circumstances. PHMSA also agrees with NAPSR and other commenters that additional requirements are needed for assessing more miles of pipeline that pose a risk to the public. PHMSA has also identified the need to address specific issues related to the selection of integrity assessment methods that have been identified following the San Bruno incident, especially related to the use of direct assessment. Therefore, PHMSA proposes to add more specific requirements related to (1) performance of integrity assessments for pipe not covered by subpart O (*i.e.,* pipeline not located in a high consequence area) that represents risk to the public, and (2) selection of assessment methods. Specifically, PHMSA proposes to revise the requirements in §§ 192.921 and 192.937 as follows: (1) Allow direct assessment only if a line is not capable of inspection by internal inspection tools; (2) add a newly defined assessment method: ''spike'' hydrostatic test; (3) add excavation and *in situ* direct examination as an allowed assessment method; and (4) add guided wave ultrasonic testing (GWUT) as an allowed assessment method. In addition, PHMSA proposes to add a new § 192.710 to require that a significant portion of pipelines not covered by subpart O be periodically assessed using integrity assessment techniques similar to those proposed for HCA segments. Specifically, PHMSA proposes to require that all pipeline segments in class 3 and class 4 locations and moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs''), be periodically assessed. Although PHMSA proposes to provide selected, more prescriptive requirements for the selection of assessment methods, the pipeline safety regulations would continue to allow the use of other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe (comparable to a specified integrity assessment such as pressure testing or inline inspection), in order to continue to encourage research and development of more effective assessment technologies similar to the successful development of GWUT. For non-HCA segments, operator notification to PHMSA of the selection of other technologies would not be required.

PHMSA understands the Pipeline Safety Trust's recommendation that the regulations require PHMSA's review and approval of any IM program. PHMSA believes its current approach to inspection of operator IM programs is both flexible and appropriate.

Comments Submitted for Questions in Topic G

G.1. Have any anomalies been identified that require repair through various assessment methods (e.g., number of immediate and total repairs per mile resulting from ILI assessments, pressure tests, or direct assessments)?

1. INGAA reported that operators have used in-line inspection, pressure testing, and direct assessment, with in-line inspection being most prevalent. INGAA commented that all three methods have been successful at identifying anomalies requiring repair. A number of pipeline operators supported INGAA's comments.

2. AGA and Ameren Illinois stated that all assessment methods used by pipeline operators have been used to identify, or have identified, anomalies requiring repair. A number of pipeline operators supported AGA's comments.

3. Accufacts recommended that PHMSA publically report the number of anomalies discovered and repaired by anomaly type, time to repair, state, and assessment method for both HCAs and non-HCAs.

4. Texas Pipeline Association, Texas Oil & Gas Association, Atmos, Paiute, and Southwest Gas noted that the transmission pipeline annual report includes the number of immediate and scheduled anomalies identified by each assessment method.

5. ITT Exelis Geospatial Systems reported that aerial leak surveys using laser technology, which is not one of the assessment methods specified in the regulations, have been successful in identifying pipeline leaks.

6. Kern River reported that it did not identify any immediate or scheduled repairs from January 1, 2004, through December 31, 2010.

7. MidAmerican noted that it has used all three allowed assessment methods. Approximately 42 percent of the company's pipeline has been assessed using direct assessment. All anomalies requiring repair have been identified using in-line inspection.

8. Northern Natural Gas reported that it identified seven immediate repair anomalies in the period from January 1, 2004, through December 31, 2010. The total number of repairs made during this same period averaged 0.1 per mile.

9. An anonymous commenter noted that few leaks are detected using subpart J pressure testing.

10. GPTC reported that it has no data with which to respond to this question.

Response to Question G.1 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that all three methods have been successful at identifying anomalies requiring repair. However, by its nature, direct assessment is a sampling-type assessment method. Hydrostatic pressure testing and in-line inspection both assess the entire segment. PHMSA, therefore, believes that these methods provide a higher level of assurance (though still not 100%) that no injurious pipeline defects remain in the pipe after the assessment is completed and anomalies repaired. Based on this inherent difference, PHMSA proposes to revise the requirements to: (1) Allow direct assessment only if a line is not capable of inspection by internal inspection tools; (2) add a newly defined assessment method: ''spike'' hydrostatic test; (3) add excavation and *in situ* direct examination as an allowed assessment method; and (4) add guided wave ultrasonic testing (GWUT) as an allowed assessment method.

G.2. Should the regulations require assessment using ILI whenever possible, since that method appears to provide the most information about pipeline conditions? Should restrictions on the use of assessment technologies other than ILI be strengthened? If so, in what respect? Should PHMSA prescribe or develop voluntary ILI tool types for conducting integrity assessments for specific threats such as corrosion metal loss, dents and other mechanical damage, longitudinal seam quality, SCC, or other attributes?

1. INGAA, supported by a number of its pipeline operator members, noted that ILI is effective, but has its own limitations; pressure testing and direct assessment can provide information that ILI cannot. INGAA commented that operators must be allowed to use all assessment techniques without encumbrances or conditions because all techniques are effective.

2. AGA and a number of its members commented that ILI is one option of a variety of methods available to operators and suggested that applying additional ILI assessment requirements would hinder operators' ability to select the tool with the appropriate capabilities to address pipeline threats. AGA commented that this would be inappropriate and operators must be allowed to use any of the three assessment methods, without conditions, based on the circumstances and threats applicable to their pipelines.

3. Air Products and Chemicals, Inc. opposed a requirement to use ILI whenever possible. The company noted

that one of the benefits of the current IM framework is the flexibility it provides to operators in how to achieve regulatory goals. Air Products noted that use of alternative methods is already constrained by regulation and contended that the existing limitations are adequate and it would be inappropriate for PHMSA to specify particular tool types for individual threats. Atmos agreed, noting that ILI is not the only assessment method applicable to many threats. Atmos noted that ILI technology is developing at a rapid pace, and suggested that prescribing certain tool types could limit future advancements or cause the rate of development to be slowed.

4. TransCanada opposed requiring use of ILI. The company noted that ILI has its advantages, but it also has limitations, and commented that operators must be able to select the methods best suited to evaluate identified threats, given the wide range of circumstances and threats that may be applicable to particular pipeline segments.

5. NACE International noted that assessments using only ILI do not necessarily provide the most information about pipeline conditions; other assessment methods may be more appropriate for some threats. NACE also noted that not all pipelines are piggable. NACE believes that each assessment method has strengths and weaknesses, each should be used where appropriate, and overly prescriptive rules can supplant sound engineering judgment, stifle innovation, and prevent the development of new technologies.

6. Accufacts commented that all new pipelines should be configured to permit ILI and a timetable should be established to convert older pipelines for ILI. At the same time, Accufacts cautioned that one particular approach to ILI should not be oversold, and suggested that limitations on use of certain assessment methods should be strongly clarified in regulations. Accufacts suggested that PHMSA needs to clarify the major strengths and weaknesses of the various assessment methods identified and to improve subpart J, including requiring the reporting of hydro testing pressure ranges, both minimum and maximum pressures, as a percentage of SMYS when appropriate.

7. MidAmerican suggested that operators be allowed to address threats by category using the guidance in ASME/ANSI B31.8S. MidAmerican noted that it cannot use ILI on all of its transmission pipelines, 42 percent of which have been assessed using direct assessment. MidAmerican suggested that operators continue to use their threat assessments to determine which pipelines should be retrofitted to accommodate ILI.

8. Northern Natural Gas reported that it uses ILI whenever possible but it cannot be used on all of its lines due to their small diameter. Northern noted that pressure testing and direct assessment may be more appropriate for some threats and that the operator is responsible for selecting the best assessment method. Northern opined that the guidance on tool selection in ASME/ANSI B31.8S is sufficient.

9. Texas Pipeline Association and Texas Oil & Gas Association recommended that ILI not be the required assessment method of choice and that operators continue to have the flexibility to select the appropriate assessment method, noting that other methods may be better for a particular threat. The associations noted that ILI technology is improving rapidly and expressed concern that rulemaking cannot keep pace with technological advancement and that prescribing tools could result in assessments being conducted with inferior technology.

10. Thomas M. Lael, an industry consultant, noted that no assessment method, including ILI, is perfect. Lael suggested that use of alternating methods be required to realize the strengths of all methods.

11. A citizen commenter suggested that use of direct assessment be limited, since it does not provide sufficient information about the pipeline.

12. An anonymous commenter noted that requiring ILI would not be cost beneficial, because corrosion metal loss is a relatively slow process.

13. GPTC noted that ILI cannot be used on all pipelines and recommended that operators have the latitude to select the assessment method most appropriate for their pipelines. Oleksa and Associates similarly noted that ILI cannot be used on some pipelines.

14. Paiute and Southwest Gas opposed a requirement to use ILI whenever possible. The companies noted that ILI provides current pipe conditions but no information on environmental conditions surrounding the pipe. They commented that operators should not be discouraged from using any appropriate assessment method.

15. Ameren Illinois opposed requiring the use of ILI, noting that it is neither practical nor feasible to require ILI assessments on all pipelines.

16. California Public Utilities Commission recommended that pressure testing and ILI be the only methods allowed for IM assessments. CPUC suggested that the use of direct assessment be limited to confirmatory direct assessments and lines that have been pressure tested to subpart J requirements. CPUC further recommended that the regulations prescribe acceptable ILI tool types to address specific threats.

17. A private citizen suggested that pressure testing should not be allowed as an assessment method because it provides no information about anomalies not resulting in leaks or failures. The commenter suggested that use of pressure testing should be limited to verifying the integrity of new or repaired pipelines.

Response to Question G.2 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that operators should be able to select the methods best suited to evaluate identified threats. However, PHMSA believes rulemaking for strengthening requirements for the selection and use of assessment methods is needed to address specific issues identified from the San Bruno incident. PHMSA proposes more prescriptive guidance for the selection of assessment methods, especially related to the use of direct assessment and to assess for cracks and crack-like defects, as indicated in the response to general comments, above. For HCA segments, PHMSA proposes that the use of direct assessment as the assessment method would be allowed only if the pipeline is not capable of being inspected by internal, in-line inspection tools. For non-HCA segments, assessments would have to be done within 15 years and every 20 years thereafter. To facilitate the identification of non-HCA areas that require integrity assessment, PHMSA proposes to define a ''Moderate Consequence Area'' or MCA. PHMSA also proposes additional requirements for selection and use of internal inspection tools, including a requirement to explicitly consider uncertainties such as tool tolerance in reported results in identifying anomalies.

PHMSA disagrees with the suggestion that pressure testing should not be allowed as an assessment method. In many circumstances, pressure testing is a good indicator of a pipeline's integrity. Although it does not assess subcritical defects, it provides assurance of adequate design safety margin and can be useful in particular for lines that are not piggable.

G.3. Direct assessment is not a valid method to use where there are pipe properties or other essential data gaps. How do operators decide whether their

knowledge of pipeline characteristics and their confidence in that knowledge is adequate to allow the use of direct assessment?

1. Industry commenters, including AGA, INGAA, Texas Pipeline Association, Texas Oil and Gas Association, and numerous pipeline operators noted that the requirements applicable to direct assessment, specified in NACE Standard SP0502–2008 and incorporated into subpart O by reference, require a feasibility study to determine if use of direct assessment is appropriate. If it cannot be determined during the pre-assessment phase that adequate data is available, another assessment method must be selected. Industry commenters noted that it is the operator's responsibility to select an appropriate assessment method.

2. Paiute and Southwest Gas disagreed with the statement that ''direct assessment is not a valid method to use where there are pipe properties or other essential data gaps.'' The companies noted that the data gathered and evaluated conforms to Section 4 of ASME/ANSI B31.8S (incorporated by reference) which allows use of conservative proxy values when data gaps exist.

3. California Public Utilities Commission recommended that pressure testing and ILI be the only methods allowed for IM assessments. CPUC suggested that use of direct assessment be limited to confirmatory direct assessments and lines that have been pressure tested to subpart J requirements.

Response to Question G.3 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that pressure testing and ILI are preferred integrity assessment methods, over direct assessment. However, when properly implemented, DA can be a valuable integrity assessment tool. PHMSA proposes to retain direct assessment as an assessment method where warranted, but proposes to revise the requirements in §§ 192.921 and 192.937 to allow use of direct assessment or other method only if a line is not capable of inspection by internal inspection tools.

G.4. How many miles of gas transmission pipeline have been modified to accommodate ILI inspection tools? Should PHMSA consider additional requirements to expand such modifications? If so, how should these requirements be structured?

1. A number of industry commenters submitted data concerning the number of pipeline miles that have been modified to accommodate ILI:

- INGAA reported that more than 30,000 miles of pipeline have been modified across the industry.
- Atmos reported that it has modified approximately 2,800 miles.
- Northern Natural Gas reported that it has modified approximately 2,500 miles.
- MidAmerican reported that it has modified 38 miles.
- Paiute and Southwest Gas reported that they have made modifications but have not tracked the total mileage on which they were performed.
- Ameren Illinois and Kern River reported that they have modified no pipelines. Kern River noted specifically that all of its mainline is piggable.

2. AGA reported that it has no data concerning the number of miles modified, but noted that operators are required to assure that new and replaced pipelines can accommodate ILI tools. AGA contended that modifying pipelines to accommodate ILI tools is more onerous for intrastate transmission pipeline operators than for interstate operators. A number of operators supported AGA's comments.

3. Texas Pipeline Association and GPTC reported that they have no data with which to respond to this question.

4. California Public Utilities Commission supported additional requirements to expand modifications to accommodate ILI but reported that it has no opinion on how these requirements should be structured.

5. MidAmerican noted that one-third of its 770 miles of transmission pipeline is of a diameter smaller than available ILI tools.

6. Northern Natural Gas commented that PHMSA should not consider additional requirements to expand modifications of pipelines to accommodate ILI tools, and that the inspection method and determination to assess additional line segments outside of HCAs should be based on specific risk factors and type and configuration of pipeline facility. The company noted that some lines cannot be assessed using ILI.

7. Paiute and Southwest Gas noted that § 192.150 requires that newly constructed or replacement pipelines be designed to accommodate ILI tools. They contended that the decision to modify other pipelines should be an operator decision based on the best assessment method.

8. Texas Pipeline Association and Texas Oil & Gas Association opined that PHMSA does not need to develop additional requirements for the modification of transmission pipelines to accommodate ILI tools. The associations noted that the regulations already cover this for new and replacement pipelines and that there is a financial incentive for operators to use ILI tools versus other assessment methods. Atmos agreed, also noting that there are numerous advantages to ILI that incentivize operators to use that method when they can.

9. Accufacts commented that PHMSA should report publicly the number of miles of transmission pipeline that can be inspected by ILI as well as the number of miles inspected by other assessment methods both for HCAs and non-HCAs.

Response to Question G.4 Comments

PHMSA appreciates the information provided by the commenters. In its report on the San Bruno incident, the NTSB recommended that all natural gas transmission pipelines be configured so as to accommodate in-line inspection tools, with priority given to older pipelines (recommendation P–11–17). In its initial response to the NTSB recommendation, PHMSA stated that implementing this recommendation will involve significant technical and economic challenges and is likely to require time to implement. Additional data is needed to evaluate this issue. Therefore, further rulemaking will be considered separately in order to complete this evaluation. PHMSA will review the comments received on the ANPRM and will address this issue in the future.

G.5. What standards are used to conduct ILI assessments? Should these standards be incorporated by reference into the regulations? Should they be voluntary?

1. INGAA, supported by a number of its operator members, noted that standards are continuously upgraded and improved and recommended that PHMSA adopt performance-based language that will allow operators to select appropriate standards.

2. AGA, supported by a number of its members, noted that ILI technology is advancing rapidly and it would be unwise to restrict innovation by handcuffing it to a slow-developing rulemaking process. AGA recommended that PHMSA not adopt ILI standards into the code. Ameren Illinois agreed that standards should not be incorporated, because to do so would limit operators' ability to use up-to-date standards.

3. GPTC argued that there is no justification to enact additional prescriptive regulations for ILI assessments of pipelines. GPTC contended that performance standards allow operators to select the best approach.

4. Atmos, MidAmerican, Northern Natural Gas, Paiute, and Southwest Gas all cited one or more of API1163, ASNT ILI–PQ–2005 and RP0102–2002, and ASME/ANSI B31.8S as standards used to conduct ILI assessments. All agreed that use of industry standards should remain voluntary. Paiute and Southwest Gas, in particular, commented that technology is developing rapidly, and that incorporating current standards into the regulations may hold operators accountable to a level of performance that may be outdated.

5. Texas Pipeline Association and Texas Oil & Gas Association also opposed incorporating ILI standards into the regulations. TPA commented that there are incentives for operators to take appropriate measures to obtain accurate and reliable ILI results.

6. An anonymous commenter suggested that incorporating standards could be counterproductive, since operators would usually stop with the required actions. The commenter suggested that a better approach would be to require operators to have precise specifications, guidelines, and a written process for ILI, none of which should be developed by the operator's ILI vendor. The commenter also suggested that a similar approach be adopted for stress corrosion cracking direct assessment (SCCDA).

7. California Public Utilities Commission and a private citizen recommended that standards be incorporated for mandatory compliance, arguing that this is necessary to assure quality and accuracy.

Response to Question G.5 Comments

PHMSA appreciates the information provided by the commenters. The current pipeline safety regulations in 49 CFR 192.921 and 192.937 require that operators assess the material condition of pipelines in certain circumstances and allow use of in-line inspection tools for these assessments. Operators are required to follow the requirements of ASME/ANSI B31.8S in selecting the appropriate ILI tools. ASME B31.8S provides limited guidance for conducting ILI assessments. At the time these rules were promulgated, there was no consensus industry standard that addressed ILI. Three related standards have been published: API STD 1163–2005, NACE SP0102–2010, and ANSI/ASNT ILI–PQ–2010. These standards address the qualification of inline inspection systems, the procedure for performing ILI, and the qualification of personnel conducting ILI, respectively. The incorporation of these standards into pipeline safety regulations will promote a higher level of safety by establishing consistent standards. Therefore, PHMSA is proposing to incorporate these industry standards into the regulations to provide better guidance for conducting integrity assessments with in-line inspection. PHMSA also encourages and actively supports the development of new and better technology for integrity assessments. Therefore, the rule also allows the application and use of new technology, provided that PHMSA is notified in advance. PHMSA will continue to evaluate the need for additional guidance for conducting integrity assessments or applying new technology.

G.6. What standards are used to conduct internal corrosion direct assessment (ICDA) and SCCDA assessments? Should these standards be incorporated into the regulations? If the commenter believes they should be incorporated into the regulations, why? What, if any, remediation, hydrostatic test or replacement standards should be incorporated into the regulations to address internal corrosion and SCC?

1. INGAA commented that standards exist for ICDA and SCCDA. AGA agreed that NACE SP0206 addresses ICDA and SP0204 addresses SCCDA. AGA opposed adopting these standards into the regulations, however, commenting that a standard must be demonstrated to be effective before it can be incorporated. AGA noted that there are long-standing issues with the ICDA standard. Numerous pipeline operators provided comments supporting the INGAA and AGA comments.

2. GPTC, Atmos, Ameren Illinois, MidAmerican, Paiute, Southwest Gas, Texas Gas Association and Texas Oil & Gas Association all referenced one or more of: NACE SP0502, NACE SP0206, ASME/ANSI B31.8S, and GRI02–0057. All agreed that the standards should not be incorporated by reference, arguing that this would stifle innovation or require operators to follow requirements that may become outdated, or both. Paiute and Southwest Gas specifically recommended that PHMSA collect additional information on industry best practices and compile/review IM results related to internal corrosion and SCC before taking any action towards incorporating the standards.

3. NACE International reported its conclusion that the existing standards for ICDA and SCCDA should be incorporated into regulations. NACE also cautioned that overly-prescriptive regulations can prevent innovation and development of new technologies.

4. Northern Natural Gas reported that it used NACE SP0206 in developing its ICDA procedures and there would be no impact on the company if the standard were adopted into regulations. Northern further reported it does not use SCCDA.

5. Accufacts commented that few technical gains have been made in the abilities of direct assessment methods to reliably identify or assess at-risk anomalies, especially with regards to SCC.

6. California Public Utilities Commission argued that pressure testing and ILI should be the only assessment methods allowed. The Commission contended that direct assessment should be limited to use during confirmatory direct assessments and for lines that have been pressure tested to subpart J requirements.

7. An anonymous commenter noted that Kiefner, NACE, and ASTM all provide useful references for SCCDA and ICDA.

8. INGAA, supported by several of its operator members, noted that ASME/ANSI B31.8S addresses remediation and pressure testing. INGAA recommended that PHMSA adopt the 2010 version of this standard, arguing that it is improved over the 2004 standard that is currently incorporated by reference into Section 192.7 and that it addresses near-neutral SCC. The 2010 edition also includes specific guidance for SCC mitigation by means of hydrostatic pressure testing in the event SCC is identified on a pipeline.

9. MidAmerican reported that it uses ASME B31G to determine remaining wall strength and that it remediates conditions in accordance with § 192.933(d) and ASME/ANSI B31.8S.

Response to Question G.6 comments

PHMSA appreciates the information provided by the commenters. Section 192.927 specifies requirements for gas transmission pipeline operators who use ICDA for IM assessments. The requirements in § 192.927 were promulgated before there were consensus standards published that addressed ICDA. Section 192.927 requires that operators follow ASME/ANSI B31.8S provisions related to ICDA. PHMSA has reviewed NACE SP0206–2006 and finds that it is more comprehensive and rigorous than either § 192.927 or ASME B31.8S in many respects. In addition, Section 192.929 specifies requirements for gas transmission pipeline operators who use SCCDA for IM assessments. The requirements in § 192.929 were promulgated before there were consensus industry standards published that addressed SCCDA. Section 192.929 requires that operators follow Appendix A3 of ASME/ANSI B31.8S. This appendix provides some guidance for

conducting SCCDA, but is limited to SCC that occurs in high-pH environments. Experience has shown that pipelines also can experience SCC degradation in areas where the surrounding soil has a pH near neutral (referred to as near-neutral SCC). NACE Standard Practice SP0204–2008 addresses near-neutral SCC in addition to high-pH SCC. In addition, the NACE recommended practice provides technical guidelines and process requirements which are both more comprehensive and rigorous for conducting SCCDA than either § 192.929 or ASME/ANSI B31.8S. Therefore, PHMSA is proposing to incorporate these industry standards into the regulations to provide better guidance for conducting integrity assessments with ICDA or SCCDA. PHMSA will continue to evaluate the need for additional guidance for conducting integrity assessments.

G.7. Does NACE SP0204–2008 (formerly RP0204), ''Stress Corrosion Cracking Direct Assessment Methodology'' address the full life cycle concerns associated with SCC?

1. INGAA suggested NACE SP0204, by itself, does not address the full life cycle concerns of SCC but in combination with ASME/ANSI B31.8S the full life cycle concerns are addressed. A number of pipeline operators supported INGAA's comments.

2. AGA, supported by a number of its members, suggested PHMSA should determine whether NACE SP0204 addresses full life cycle concerns.

3. GPTC, Texas Pipeline Association, Texas Oil & Gas Association, and Ameren Illinois commented it was not clear what PHMSA meant by ''full life cycle concerns.''

4. NACE International reported that SP0204 does not address the full life cycle concerns of SCC; however, NACE noted that it has developed a 2011 ''Guide to Improving Pipeline Safety by Corrosion Management'' which will be converted into a NACE standard.

5. MidAmerican reported its conclusion that NACE SP0204 does address full life cycle concerns.

6. Paiute and Southwest Gas reported their conclusion that the existing standards are adequate, but deferred to NACE concerning the breadth of coverage of NACE standards.

Response to Question G.7 Comments

PHMSA appreciates the information provided by the commenters. PHMSA believes that NACE SP0204–2008 is the best available guidance and is proposing to incorporate this industry standard into the regulations for conducting integrity assessments with SCCDA. In addition, other proposed requirements for integrity assessments and remediation in §§ 192.710, 192.713, 192.624, and subpart O provide greater assurance that the full life cycle concerns associated with SCC are addressed.

G.8. Are there statistics available on the extent to which the application of NACE SP0204–2008, or other standards, have affected the number of SCC indications operators have detected and remediated on their pipelines?

1. Industry commenters responding to this question unanimously noted that no statistics have been collected on the use of NACE SP0204. INGAA noted, in addition, that the SCC Joint Industry Project (JIP) represents the experience of operators of 160,000 miles of gas transmission pipeline.

2. Paiute and Southwest Gas reported that they have not identified any SCC on their pipeline systems.

3. An anonymous commenter noted that there has been one incident attributed to factors not addressed in current standards. The commenter noted that the only common factors among SCC colonies was high soil resistivity and disbanded coating.

Response to Question G.8 Comments

PHMSA appreciates the information provided by the commenters. As described in the response to Question G.6, PHMSA is proposing to incorporate NACE SP0204–2008 into the regulations. PHMSA will continue to gather information in this area and will evaluate the need for more specific requirements or guidance to address the threat of SCC.

G.9. Should a one-time pressure test be required to address manufacturing and construction defects?

1. INGAA and a number of its pipeline operators argued that this should be a case-by-case decision guided by INGAA's Fitness for Service protocol. INGAA noted that new pipelines require a part 192, subpart J, pressure test while older pipelines may have been strength tested.

2. AGA, supported by a number of its pipeline operators, opined that a one-time pressure test is sufficient. AGA noted that Congress accepted the stability of pipelines that had undergone a post construction pressure test.

3. GPTC argued that a one-time pressure test is sufficient; however, such a test should not be mandated for pipelines not tested after construction unless a significant risk has been demonstrated. GPTC noted that manufacturing and construction defects are not time-related.

4. American Public Gas Association objected to any requirement for a one-time pressure test, noting that it is not practical to conduct such a test on most transmission pipelines operated by municipal pipeline operators.

5. Atmos noted that the decision to perform one-time pressure tests to address manufacturing and construction defects requires more information and consideration than can be conveyed in response to a single question. Atmos reported that it could not determine if the one-time pressure test requirement would apply to all pipeline segments or to pipelines with certain characteristics. Some of Atmos' pipelines could not be removed from service for testing without impacts on customers.

6. Ameren Illinois argued that no one-time pressure test should be required, noting that a pressure test is already required before a pipeline is placed in service.

7. Northern Natural Gas argued that a one-time pressure test should not be required in all cases. Northern noted that assessment of manufacturing and construction defect threats should be determined based on the risk level and pipeline type for pipeline segments do not have an existing pressure test.

8. MidAmerican opined that a one-time pressure test should be a requirement for manufacturing and construction defects, noting defects that survive a pressure test are unlikely to fail during the useful life of the pipeline.

9. Oleksa and Associates noted that: (1) A one-time pressure test is all that is needed for manufacturing and construction defects; (2) an in-service pipeline should only be pressure tested if there is clear reason to believe a strength test would be beneficial; and (3) many pipelines operate at such low levels of stress that a strength test is not necessary.

10. Paiute and Southwest Gas commented that a pressure test should be conducted in accordance with subpart J when initially placing a pipeline in service. The operators reported that they support the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 which will require systematic pressure testing (or other alternative methods of equal or greater effectiveness) of certain, previously untested transmission pipelines located in HCAs and operating at a pressure greater than 30% SMYS. Texas Pipeline Association and Texas Oil & Gas Association agreed, noting that testing of new pipelines is already required and the Act requires use of pressure testing or alternate means to verify MAOP.

11. Thomas Lael and California Public Utilities Commission argued that all pipelines should be subjected to a pressure test. CPUC noted that an unspecified technical paper published by Kiefner shows that a pressure test to 1.25 times MAOP will be sufficient to demonstrate the stability of manufacturing and construction defects and girth welds.

12. The NTSB recommended that PHMSA amend part 192 so that manufacturing and construction defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP.

13. Accufacts suggested that a requirement for a one-time pressure test is needed, noting the NTSB safety recommendations issued following San Bruno made it clear that there are problems with the current IM regulations, especially as they relate to systems that were in operation before the implementation of federal regulations.

14. A private citizen suggested that a one-time pressure test or reduction of MAOP should be required for all low-frequency electric resistance welded (LFERW) pipe.

15. A private citizen suggested that a one-time pressure test conducted in combination with ILI should be required as a baseline for subsequent ILI inspections.

16. An anonymous commenter opined that no one-time pressure test is needed unless there is a history of seam failure or SCC.

Response to Question G.9 Comments

PHMSA appreciates the information provided by the commenters. The majority of comments support performance of a one-time pressure test to address manufacturing and construction defects. The ANPRM requested comments regarding proposed changes to part 192 regulations that would repeal 49 CFR 192.619(c) and the NTSB issued recommendations to repeal 49 CFR 192.619(c) for all gas transmission pipelines (P–11–14) and to require a pressure test before concluding that manufacturing- and construction-related defects can be considered stable (P–11–15). In addition, Section 23 of the Act requires issuance of regulations regarding the use of tests to confirm the material strength of previously untested natural gas transmission lines.

An Integrity Verification Process (IVP) workshop was held in 2013. At the workshop, PHMSA, the National Association of State Pipeline Safety Representatives, and various other stakeholders presented information and comments were sought on a proposed IVP that will help address these issues. Key aspects of the proposed IVP process include criteria for establishing which pipe segments would be subject to the IVP, technical requirements for verifying material properties where adequate records are not available, and technical requirements for re-establishing MAOP where adequate records are not available or the existing MAOP was established under § 192.619(c). Comments were received from the American Gas Association, the Interstate Natural Gas Association of America, and other stakeholders and addressed the draft IVP flow chart, technical concerns for implementing the proposed IVP, and other issues. The detailed comments are available on Docket No. PHMSA–2013–0119. PHMSA considered and incorporated the stakeholder input, as appropriate into this NPRM, which proposes requirements to address pipelines that established MAOP under 49 CFR 192.619(c), manufacturing and construction defect stability, verification of MAOP (where records that establish MAOP are not available or inadequate), and verification and documentation of pipeline material for certain onshore, steel, gas transmission pipelines.

G.10. Have operators conducted quality audits of direct assessments to determine the effectiveness of direct assessment in identifying pipeline defects?

1. INGAA, AGA, GPTC, and numerous pipeline operators noted that direct assessment is a cyclical process that continually incorporates analysis of information made available from the direct and indirect assessment tools used. The direct assessment process requires that more restrictive criteria be applied on first use and as operators become more experienced with the methodology and gather more data on the pipeline, more informed pipeline integrity decisions are made. The commenters stated that operators using the direct assessment process must continuously assess the effectiveness of the methodology.

2. Paiute and Southwest gas commented that operators confirm the findings of the pre-assessment and indirect assessment steps as part of the four-step direct assessment process. Validation digs are required to confirm the effectiveness of the direct assessment process.

3. Texas Pipeline Association and Texas Oil & Gas Association noted that direct examinations are made as part of every direct assessment. In Texas, operators have generally been required by the Railroad Commission to demonstrate comparisons of direct assessment results to ILI results on a portion of their pipeline where both have been performed. The associations contended that this process of validating should be considered a quality audit.

4. Northern Natural Gas agreed that verification of the effectiveness of direct assessment is already a part of the required post-assessment step of the four-step direct assessment process. Ameren Illinois agreed that this process is effectively a quality audit.

5. Atmos reported that records are kept of the indicated anomalies and the actual anomalies discovered through direct examination, thus assuring the quality and validation of direct assessments.

6. Accufacts opined that there appear to be serious deficiencies in the application of direct assessment on gas pipelines.

7. An anonymous commenter noted that direct assessment, if used correctly, is informative and proactive, and best suited to identify preventive and mitigative actions and to establish assessment intervals.

Response to Question G.10 Comments

PHMSA appreciates the information provided by the commenters. The majority of comments state that quality audits are performed for direct assessments, however, PHMSA believes, as one comment suggests, that there are weaknesses in the use of direct assessments. For example, SCCDA is not as effective, and does not provide an equivalent understanding of pipe conditions with respect to SCC defects, as ILI or hydrostatic pressure testing. Accordingly, PHMSA proposes to revise the requirements in §§ 192.921 and 192.937 for direct assessment to allow use of this method only if a line is not capable of inspection by internal inspection tools.

G.11. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

H. Valve Spacing and the Need for Remotely or Automatically Controlled Valves

The ANPRM requested comments regarding proposed changes to the requirements for sectionalizing block valves. Gas transmission pipelines are required to incorporate sectionalizing block valves. These valves can be used to isolate a section of the pipeline for maintenance or in response to an incident. Valves are required to be installed at closer intervals in areas where the population density near the pipeline is higher.

Sectionalizing block valves are not required to be remotely-operable or to operate automatically in the event of an unexpected reduction in pressure (*e.g.,* from a pipeline rupture). Congress has previously required PHMSA to ''assess the effectiveness of remotely controlled valves to shut off the flow of natural gas in the event of a rupture'' and to require use of such valves if they were shown technically and economically feasible.[36] The NTSB has also issued a number of recommendations concerning requirements for use of automatic- or remotely-operated mainline valves, including one following a 1994 pipeline rupture in Edison, NJ.[37] The incident in San Bruno, CA on September 9, 2010, has raised public concern about the ability of pipeline operators to isolate sections of gas transmission pipelines in the event of an accident promptly and whether remotely or automatically operated valves should be required to assure this.

The ANPRM then listed questions for consideration and comment. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic H

1. INGAA argued that while valves, spacing, and selection are important, public safety requires a broader review of incident responses and consequences. Performance-based Incident Mitigation Management (IMM), using valves and other tools, will, according to INGAA, improve incident response, reduce incident duration and minimize adverse impacts. IMM plans identify comprehensive actions that improve mitigation performance and minimize overall incident impact. These plans cover various aspects of response, including how operators detect failures, how they place and operate valves, how they evacuate natural gas from pipeline segments, and how they prioritize coordination efforts with emergency responders. A number of pipeline operators supported INGAA's comments, including Panhandle, TransCanada, Spectra Williams, Southern Star, and others.

2. AGA submitted a white paper that discussed potential benefits associated with remote control valves and automatic shutoff valves; however, the paper acknowledged that these valves will not prevent incidents. A number of pipeline operators supported AGA's comments.

3. APGA reported automatic or remotely-controlled valves are not practical for municipal pipeline operators because they do not have remote monitoring or control of their pipelines. APGA also cautioned that the use of automatic valves could lead to false closures, an unintended and adverse consequence.

4. Atmos commented that the existing requirements for valve spacing allow for safe and reliable service to its customers. The company noted that requiring the installation of remote control valves or automatic shutoff valves would add minimal value to the overall safety and operation of its transmission pipeline systems. In addition, industry studies have concluded that remote or automatic features on block valves would not reduce injuries or fatalities associated with an incident.

5. MidAmerican commented that installation of automatic shutoff valves would be costly, have minimal impact on improving safety, and could cause customer outages on its pipeline system. At the same time, MidAmerican acknowledged that some applications of remote/automatic control valves could have merit, but that the election should lie with the operator given the complexity of pipeline systems and other factors that bear on that decision. MidAmerican reported its conclusion that ASME/ANSI B31.8S provides adequate guidance for the installation of sectionalizing valves. While MidAmerican opposes a requirement to install automatic or remotely-controlled valves, the company suggested factors PHMSA should consider if it decides to adopt such a requirement. Specifically, PHMSA should allow operators flexibility in deciding between automatic and remote valves and should clarify when action on a pipeline is considered a new installation versus a repair or replacement in-kind.

6. TransCanada noted that industry studies have shown automatic or remote block valves do not prevent incidents and have a minimal effect on significant consequences, since most of the human impacts from a rupture occur in the first few seconds, well before any valve technology could reduce the flow of natural gas. TransCanada supports the use of Incident Mitigation Management (IMM) to improve incident response, reduce incident duration, and minimize adverse impacts.

7. Chevron argued operators should have the flexibility to select the most effective measures based on specific locations, risks, and conditions of the pipeline segment. Chevron noted that the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 requires a study of incident response in HCAs that must consider the swiftness of leak detection and pipeline shut-down capabilities and the location of the nearest personnel. The study must also evaluate the costs, risks, and benefits of installing automatic or remote controlled shut-off valves.

8. A private citizen suggested that periodic drills be held with local emergency responders, pipeline operators should provide specialized equipment to local responders in densely populated areas, and pipeline operators pay a fee to those municipalities to support incident response. The commenter further recommended that leak detection analyses be computerized.

9. Dominion East Ohio contended that current regulations are adequate and that automatic shutoff valves and remote control valves are an important preventive and mitigative measure to consider using. However, these valves do not prevent accidents and have very limited impact in preventing injuries and deaths caused by an initial pipeline failure.

10. Accufacts suggested that further prescriptive regulation is required concerning the placement, selection, and choice of manual, remotely-controlled, or automatic shutoff valves.

11. The Pipeline Safety Trust (PST) questioned the conclusions of the DOT study, ''Remotely Controlled Valves on Interstate Natural Gas Pipelines, (Feasibility Determination Mandated by the Accountable Pipeline Safety and Partnership Act of 1996), September 1999, which concluded that remote control valves were and remain economically unfeasible. The PST noted that the study also stated that there could be a potential benefit in terminating the gas flow to a rupture

[36] Accountable Pipeline Safety and Partnership Act of 1996, Public Law 104–304.

[37] National Transportation Safety Board, ''Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994,'' PB95–916501, NTSB/PAR–95/01, January 18, 1995.

expeditiously particularly in heavily populated and commercial areas. PST suggested PHMSA commission an independent analysis to reach a conclusion regarding whether to require these valves.

12. A private citizen suggested that local authorities regularly review incidents in densely populated areas, as self-policing by pipeline operators is insufficient. The commenter also recommended that pipeline construction and modifications be subject to signoff by a licensed professional engineer and be certified for compliance with applicable regulations by a corporate officer subject to criminal penalties, in order to reduce the incentive to cut corners.

13. Northern Natural Gas and a private citizen recommended that the current one-call exemptions for government agencies be eliminated.

Comments Submitted for Questions in Topic H

H.1. Are the spacing requirements for sectionalizing block valves in § 192.179 adequate? If not, why not and what should be the maximum or minimum separation distance? When class locations change as a result of population increases, should additional block valves be required to meet the new class location requirements? Should a more stringent minimum spacing of either remotely or automatically controlled valves be required between compressor stations? Under what conditions should block valves be remotely or automatically controlled? Should there be a limit on the maximum time required for an operator's maintenance crews to reach a block valve site if it is not a remotely or automatically controlled valve? What projected costs and benefits would result from a requirement for increased placement of block valves?

1. AGA and a number of pipeline operators contended that the existing requirements in § 192.179 are adequate. AGA noted that studies have shown there is no safety benefit to having more remote or automatic valves and operators should be permitted to determine the need for additional valves and spacing. AGA contended that there is no safety reason to change the existing regulation and argued that remote or automatic valves should not be mandated for any specific set of circumstances, since they are only one option for pipeline shutdown.

2. Texas Pipeline Association and Texas Oil & Gas Association commented that spacing requirements for natural gas transmission lines have been shown to be adequate for emergency situations. Both associations observed that block valves are not in place to prevent accidents and that the greatest impact of an accident is from the initial gas release, before automatic or remote valves could actuate. The associations also noted that the addition of more block valves would increase the risk to aboveground infrastructure.

3. Accufacts contended that the existing spacing requirements are inadequate and noted that valve spacing plays a significant role in the ''isolation blowdown'' time, or the time to depressurize a gas pipeline segment once isolation valves are closed after a rupture. Accufacts also recommended that additional sectionalizing valves be required when class locations change.

4. Iowa Utilities Board (IUB) suggested that ease of access and the time to respond should be factors relevant to a decision as to whether to install automatic or remote valves. IUB noted that the considerations are different for valves in remote areas compared to urban valves.

5. California Public Utilities Board reported that the issue of valve spacing is under review by the State.

6. A private citizen suggested that valves be required at one-mile intervals in densely populated urban areas and that they close automatically in the event of an incident, since the duration of the fire resulting from an incident is directly proportional to the volume of gas between valves. AGA commented that it is not the amount of gas between valves but rather it is the volume between a valve and a rupture that determines the volume released.

7. Wyoming County Pennsylvania's Commissioners suggested that it is necessary to modify separation distances and to establish adequate distances for gathering lines, including in Class 1 areas. The Commissioners acknowledged that the spacing required for Class 3 locations may be more acceptable than the spacing required for Class 1 areas, but noted that it will take longer to reach a block valve with 10 mile spacing in Pennsylvania's Marcellus Shale regions.

8. An anonymous commenter responded that current valve spacing requirements are adequate and suggested that automation be required if it would take 20 to 30 minutes to respond to a mainline valve.

9. AGA, supported by a number of pipeline operators, noted that operators evaluate the need for additional block valves when they become aware of changes in class location.

10. Atmos commented that the need for additional block valves should be evaluated when class locations change, if pipe replacement is needed to comply with the new class locations. Atmos recommended valve installations, if any, should only be required within the replaced pipeline section. Atmos further recommended that automatic or remote valves should not be required between compressor stations due to the risk of false closures and the extensive modifications that would be required.

11. MidAmerican opposed a requirement to install new block valves when a class location changes or to establish more stringent spacing requirements, noting that ASME/ANSI B31.8 provides adequate guidance for block valve considerations. Texas Pipeline Association, Texas Oil & Gas Association, and Northern Natural Gas agreed, noting that the required class location study includes consideration of current spacing as well as other criteria.

12. The Commissioners of Wyoming County Pennsylvania stated that it is imperative that a suitable number of additional block valves be required when population increases and class location changes, arguing that this is necessary to assure adequate public safety measures are in place.

13. An anonymous commenter suggested that new valves should not be required when HCA or class location boundaries change, noting that such changes occur rather frequently.

14. Northern Natural Gas argued that a prescriptive standard for valve spacing may not necessarily provide additional risk reduction, noting that many Class 2 and 3 locations are short pipe segments within an extended Class 1 location.

15. Texas Pipeline Association and Texas Oil & Gas Association noted that more block valves would not decrease the damage from a pipeline accident, noting that PHMSA studies have shown that fatalities and significant property damage occur within 3 minutes of a pipeline rupture while a remotely-operated valve takes 10 minutes to close. This and other studies have shown the only benefit to adding more valves is reducing the amount of gas lost in an accident.

16. Accufacts contended that a more scientific discussion will demonstrate a maximum spacing of eight miles will provide sufficient risk reduction.

17. MidAmerican suggested that block valves should be automatic or remotely-operated only when adequate response times cannot be achieved by operator personnel. When response times are adequate, MidAmerican contended that use of automatic or remote valves should be at the operator's discretion.

18. Northern Natural Gas suggested that the decision to use remote or automatic shut-off valves should be

based on the operator's risk assessment and should be made, by the operator, on a case-by-case basis.

19. Paiute and Southwest Gas argued that operators should have the flexibility to evaluate and determine whether remote or automatic valves would be beneficial. The companies noted that § 192.935 already requires the consideration of additional valves as a preventive and mitigative measure.

20. Accufacts contended that decisions on valve spacing and whether they should be manual, remote, or automatic will be dependent on the time established for first responders to safely enter an actual gas transmission impact zone following rupture. Accufacts noted that California has set a goal of 30 minutes for first response time.

21. A private citizen suggested that automatic shutoff valves should be used in densely populated areas because they provide the most rapid response.

22. The Commissioners of Wyoming County Pennsylvania suggested that standardization is necessary with remotely and automatically controlled shutoffs. The Commissioners contended that the operator needs to employ remote or automatic valves when transmission and gathering lines are routed through areas that are not easily accessible.

23. INGAA noted that § 192.620 requires a one-hour time frame for closing a valve, and contended this is practical for valves that would isolate pipelines in HCAs and consistent with requirements for alternative MAOP in § 192.620. A number of pipeline operators supported INGAA's comments.

24. Atmos suggested that mandating a minimum time to reach a valve site is impractical, because many variables exist in a dynamic state that affect an operator's ability to reach a block valve site.

25. MidAmerican opposed a specified time frame for response to a valve site, noting that operators should respond in an expedient manner without specified time limits.

26. Northern Natural Gas suggested PHMSA consider a two-hour response time for valves in HCA.

27. Texas Pipeline Association and Texas Oil & Gas Association noted that conditions determine how quickly an operator can reach a valve site in the event of an incident and operators make every effort to respond expeditiously when an incident occurs. The associations opposed adoption of a required response time.

28. TransCanada reported its conclusion that having personnel on site within one hour is reasonable for planning purposes. If this cannot be met, TransCanada suggested that possible valve automation should be required.

29. The Commissioners of Wyoming County Pennsylvania reported their conclusion that there would be value in establishing a maximum response time, especially in Class 1 locations where block valves may be 10 miles apart.

30. INGAA and a number of its pipeline operator members noted that studies have shown consistently that there is no value in installing additional block valves or in automating valves. They suggested that it would be more beneficial to apply resources that would be required to comply with any new requirements in this area towards preventing accidents.

31. MidAmerican reported that installing additional block valves would entail significant costs and suggested that increasing the number of valves could cost in excess of $40 million for its pipeline system. Northern Natural Gas agreed that costs could be substantial, without providing a specific estimate for its pipeline system.

32. Paiute and Southwest Gas estimated that costs to install new valves could range from $100,000 to $1 million per installation.

33. An anonymous commenter estimated that retrofitting a 36-inch valve for remote operation would cost approximately $30,000 plus subsequent maintenance costs.

34. Accufacts noted that the San Bruno accident demonstrated that there is a cost associated with not properly spacing, installing or automating valves in high consequence areas.

H.2. Should factors other than class location be considered in specifying required valve spacing?

1. INGAA, AGA, GPTC and several pipeline operators took the position that no new requirements are needed. These associations argued that § 192.179 provides appropriate minimum standards and reported that operators install additional valves in accordance with their integrity management plans or other factors that they consider voluntarily.

2. Paiute and Southwest Gas opined that no additional criteria are needed. They noted that numerous industry studies have shown that there is little or no safety benefit to installing additional automatic or remote valves. They suggested that operators should have the flexibility to determine, based on local circumstances, where additional valves are needed.

3. Atmos suggested that valve accessibility be given more consideration, noting that installing valves in locations that provide improved accessibility could lead to spacing greater than allowed under current regulations. Atmos further suggested that environmental factors such as water crossings and areas prone to flooding should be taken into consideration.

4. MidAmerican opined that additional factors should be considered and pointed to ASME/ANSI B31.8 for examples.

5. Accufacts concluded that additional factors need to be taken into consideration, noting that protection of identified sites in Class 1 and 2 locations will require shorter valve spacing than is currently required by regulations.

6. The California Public Utilities Commission noted that there are numerous factors to be considered that affect response time, and that this issue is under review by the State.

7. The Texas Pipeline Association, Texas Oil & Gas Association, and Commissioners of Wyoming County Pennsylvania suggested that factors other than class location should not be added to the regulations. They noted that class location serves as a surrogate for the level of risk posed by a pipeline.

H.3. Should the regulations be revised to require explicitly that new valves must be installed in the event of a class location change to meet the spacing requirements of § 192.179? What would be the costs and benefits associated with such a change?

1. INGAA and a number of its pipeline operator members opposed applying § 192.179 requirements retroactively to class location changes. INGAA suggested that, rather than absorbing the cost of installing new valves, other preventive and mitigative measures applied through an integrity management plan would produce greater benefits.

2. AGA and a number of its members opposed requiring new valves be installed when class location changes, arguing that no safety benefit will result.

3. Northern Natural Gas expressed its opinion that current regulations are adequate, noting that class location change studies require consideration of block valve spacing.

4. MidAmerican opined that the existing regulations are adequate and noted that ASME/ANSI B31.8 provides other factors for consideration.

5. GPTC expressed its belief that existing requirements are adequate, noting that operators voluntarily consider other factors in establishing valve locations.

6. Atmos suggested that PHMSA not require the installation of new valves

due to changes in class location, but stated the agency should consider the need for additional block valves if pipe replacement is needed as a result of the change.

7. Accufacts suggested that new valves should be required following class location changes, but suggested that a reasonable time should be provided for such valves to be installed and operational.

8. The Texas Pipeline Association and Texas Oil & Gas Association commented that no safety benefit has been demonstrated for the installation of additional valves. The associations suggested that installing additional valves could be counterproductive, since more above-ground valves could pose an additional risk to the public.

9. The California Public Utilities Commission opined that the regulations should require explicitly that additional valves be installed when class location changes, but expressly withheld an opinion on related costs.

10. A private citizen suggested that all requirements related to class location should apply when class location changes, unless PHMSA adopts an expanded definition for HCA to replace class location considerations.

11. An anonymous commenter stated that most operators anticipate changes to Class 3 or 4 when pipelines are designed and constructed. The commenter estimated that installing a new 36-inch valve would cost $70 to $100 thousand, not including down time and lost product.

12. The Commissioners of Wyoming County Pennsylvania commented that the regulations need to be revised to explicitly require that new valves be installed when class locations change. The Commissioners suggested that this needs to extend to both transmission and gathering lines in Class 1 areas.

H.4. Should the regulations require addition of valves to existing pipelines under conditions other than a change in class location?

1. INGAA and a number of pipeline operators noted that studies have indicated valve spacing has limited impact on the duration of an incident. INGAA suggested that a performance-based approach to incident mitigation management would better inform valve placement.

2. AGA opposed requiring additional valves under any scenario. A number of pipeline operators supported AGA's comments.

3. Accufacts suggested that new valves should be installed when a site becomes an HCA regardless of class location, but a reasonable time should be allowed for such valves to be installed and become operational.

4. Ameren Illinois opposed requiring new valves under other conditions, opining that existing requirements are adequate.

5. GPTC and Atmos commented that existing regulations are a sufficient baseline for determining valve location, noting that operators often use more stringent spacing criteria during initial construction.

6. MidAmerican opposed requiring that installation of new valves on existing pipelines for any reason other than a class location change, noting that ASME/ANSI B31.8 provides additional factors for operators to consider in determining valve location.

7. Northern Natural Gas noted that existing regulations require that operators consider additional valves as a preventive and mitigative measure and expressed its conclusion that this requirement is sufficient.

8. Paiute and Southwest Gas suggested that operators should have the flexibility to evaluate and determine where remotely-controlled or automatic valves would be beneficial. The companies noted that § 192.935 requires the consideration of additional valves as a preventive and mitigative measure and industry studies indicate little or no safety benefit to installing additional valves.

9. The California Public Utilities Commission suggested that conditions that would impede access to a valve may need to be considered in determining valve placement.

H.5. What percentage of current sectionalizing block valves are remotely operable? What percentage operate automatically in the event of a significant pressure reduction?

1. INGAA estimated that 40 to 50 percent of mainline block valves are remotely-operated or automatic. INGAA did not provide an estimate specifically for automatic valves. INGAA noted that application of Incident Mitigation Management would lead operators to conclusions as to whether a valve should be remote or automatic. A number of pipeline operators supported INGAA's comments.

2. AGA and GPTC reported that they have no data with which to respond to this question.

3. Ameren Illinois reported that it has no remotely-controlled valves.

4. Atmos reported that remote and automatic valves are not installed routinely. Remotely-controlled valves are installed on a small number of select pipelines, representing approximately 0.1 percent of all valves.

5. Kern River reported that 66 percent of its mainline block valves, and all block valves in HCA, are remotely-controlled.

6. MidAmerican reported that less than one percent of its valves are remotely-controlled and a similarly small percentage of them are automatic.

7. Northern Natural Gas reported that remotely-controlled valves are located only at compressor stations on its pipeline system.

8. Paiute reported that less than 10 percent of the valves on its system are remotely-controlled. Paiute has no automatic valves.

9. Southwest Gas reported that it has no remotely-controlled or automatic valves, due to the urban nature of its pipeline system.

10. Texas Pipeline Association reported that a limited survey of its members indicated the number of remotely-controlled valves varies from 1 to 18 percent; the number of automatic valves varies from zero to 18 percent.

H.6. Should PHMSA consider a requirement for all sectionalizing block valves to be capable of being controlled remotely?

1. INGAA and a number of pipeline operators opposed consideration of such a requirement. They commented that no one solution should be mandated and Incident Mitigation Management should guide operators to decisions as to which valves should be remote or automatic.

2. AGA and a number of pipeline operators also opposed consideration of such a requirement, noting remotely-controlled valves are only one option for shutting down a pipeline.

3. Accufacts opposed such a generic requirement, noting small-diameter gas transmission pipelines may not merit automation because of the science of pipeline diameter rupture associated with high heat flux releases.

4. GPTC opined that remotely-controlled valves do not improve safety, thus there is no basis for requiring their use. GPTC noted that operators voluntarily consider many factors in establishing valve locations.

5. Atmos opposed consideration of this requirement, noting there are issues with false closures and the costs of conversion or installation are extensive. Atmos also noted that industry studies have shown no increase in safety from having more remotely-controlled or automatic valves.

6. Kern River opined that this should be an operator decision, noting that integrity management regulations require the consideration of remote or automatic valves as part of identifying preventive and mitigative measures.

7. MidAmerican strongly opposed requiring all sectionalizing block valves to be remotely controlled. MidAmerican stated that the location and type of valve should be based on an engineering assessment. A requirement that all valves be remote would increase costs and may provide disincentives to installation of additional valves.

8. Northern Natural Gas opposed such a requirement, commenting this should be a case-by-case decision based on risk reduction.

9. Paiute and Southwest Gas reported their conclusion that the existing requirements in § 192.179 are adequate. The companies recommended that operators have the flexibility to evaluate and determine where remote or automatic valves would be beneficial. They noted that § 192.935 requires the consideration of additional valves as a preventive and mitigative measure and industry studies indicate little or no safety benefit to installing additional remote or automatic valves.

10. The Texas Pipeline Association and Texas Oil & Gas Association opposed consideration of a requirement that all block valves be remotely-operable. The associations noted that it would be tremendously expensive to do so, and it would require power and communication sources that may not be readily available at valve sites.

11. The California Public Utilities Commission commented that this could be impractical for distribution systems considering space limitations and the practicability of supplying communication facilities for valves. This issue is under review by the State for transmission facilities.

12. The Iowa Utilities Board noted that remotely-operated valves require a SCADA or other type of remote monitoring and operating system. A requirement that all sectionalizing valves be remotely-operable would thus be a de facto requirement that all operators, regardless of size or the potential consequences of an accident, install a SCADA system. Small operators and municipal utilities in Iowa do not have such systems.

13. The Commissioners of Wyoming County Pennsylvania commented that it might be desirable for all valves to be remotely-operable or automatic, but PHMSA must consider what is reasonable and adequate.

14. An anonymous commenter opposed consideration of a requirement that all valves be remotely-operable, noting that most gas pipeline accident consequences occur immediately upon release, before a remote valve could have any effect.

H.7. Should PHMSA strengthen existing requirements by adding prescriptive decision criteria for operator evaluation of additional valves, remote closure, and/or valve automation? Should PHMSA set specific guidelines for valve locations in or around HCAs? If so, what should they be?

1. INGAA and a number of pipeline operators opposed PHMSA's establishment of prescriptive criteria, suggesting instead that PHMSA develop guidance for Incident Mitigation Management.

2. AGA, GPTC, and a number of pipeline operators commented that requirements in § 192.179 are adequate. AGA noted that operators already consider additional valves in their emergency response portfolio and install them where economically, technically, and operationally feasible. Some operators noted that numerous industry studies indicate that there is little or no safety benefit to installing additional remote or automatic valves and § 192.935 already requires the consideration of additional valves as a preventive and mitigative measure.

3. Accufacts supported the consideration of prescriptive criteria, arguing that prescriptive regulation should be mandated for certain gas transmission pipelines in HCAs, especially larger-diameter pipelines in certain areas where manual closure times can be long.

4. Ameren Illinois opposed additional prescriptive criteria, arguing that existing requirements are sufficient and that additional valves should be considered when economically, technically, and operationally feasible to address specific safety concerns.

5. California Public Utilities Commission expressed its conclusion that prescriptive decision criteria may need to be added for all Method 1 HCA locations.

6. The Iowa Utilities Board, the Texas Pipeline Association and the Texas Oil & Gas Association questioned whether it is possible to write prescriptive decision criteria that can reasonably address all possible situations and circumstances or always provide the best option. These commenters suggested that operator judgment and discretion should play a part in these decisions.

7. MidAmerican expressed its belief that pipeline safety would not be enhanced by additional prescriptive criteria and opposed specific requirements for valve location near HCAs, noting that ASME/ANSI B31.8 provides considerations for operators to take into account when deciding on valve locations.

8. An anonymous commenter suggested that prescriptive criteria could be useful in assuring a degree of consistency among pipeline operators.

H.8. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

Response to Topic H Comments

PHMSA appreciates the information provided by the commenters. Based on the investigation of the San Bruno incident, the NTSB recommended (P–11–11) that PHMSA promulgate regulations to explicitly require that automatic shutoff valves or remote control valves in high consequence areas and in Class 3 and 4 locations be installed and spaced at intervals considering the population factors listed in the regulations. In addition, Section 4 of the Act requires issuance of regulations on the use of automatic or remote-controlled shut-off valves, or equivalent technology, if appropriate, and where economically, technically, and operationally feasible. The Act also requires the Comptroller General of the United States to complete a study on the ability of transmission pipeline facility operators to respond to a hazardous liquid or gas release from a pipeline segment located in a high-consequence area. On March 27, 2012, PHMSA sponsored a public workshop to seek stakeholder input on this issue. On October 5, 2012, PHMSA also briefed stakeholders, via a webcast, on the status of an ongoing study conducted by Oak Ridge National Laboratory on understanding the application of automatic control and remote control shutoff valves. The final study was published in December 2012. PHMSA also included this topic in the July 18, 2012 Pipeline Research Forum. PHMSA will take further action on this topic after completion of the assessment of the findings from these activities. PHMSA will consider the comments

received on the ANPRM and will consider this topic in future rulemaking, as required.

I. Corrosion Control

Gas transmission pipelines are generally constructed of steel pipe, and corrosion is a potential threat. Subpart I of part 192 addresses the requirements for corrosion control of gas transmission pipelines, including the requirements related to external corrosion, internal corrosion, and atmospheric corrosion. However, this subpart does not include requirements for the specific threat of Stress Corrosion Cracking (SCC). The ANPRM requested comments regarding revisions to subpart I to improve the specificity of existing requirements and to add requirements relative to SCC.

Existing requirements have proven effective in reducing the occurrence of incidents caused by external corrosion. Many of the provisions in subpart I, however, are general in nature. In addition, the current regulations do not include provisions that address issues that experience has shown are important to protecting pipelines from corrosion damage, including:

• Post-construction surveys for coating damage.

• Post-construction close interval survey (CIS) to assess the adequacy of cathodic protection (CP) and inform the location of CP test stations.

• Periodic interference current surveys to detect and address electrical currents that could reduce the effectiveness of CP.

• Periodic use of cleaning pigs or sampling of accumulated liquids to assure that internal corrosion is not occurring.

Corrosion control regulations applicable to gas transmission pipelines currently do not include requirements relative to SCC. SCC is cracking induced from the combined influence of tensile stress and a corrosive medium. SCC has caused numerous pipeline failures on hazardous liquids pipelines, including a 2003 failure on a Kinder Morgan pipeline in Arizona, a 2004 failure on an Explorer Pipeline Company pipeline in Oklahoma, a 2005 failure on an Enterprise Products Operating line in Missouri, and a 2008 failure on an Oneok NGL Pipeline in Iowa. More effective methods of preventing, detecting, assessing and remediating SCC in pipelines are important to making further reductions in pipeline failures.

The ANPRM then listed questions for consideration and comment. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic I

1. AGA opined that the questions posed under this topic are unclear and disjointed and do not differentiate between distribution and transmission pipelines. In addition, AGA stated that PHMSA did not provide a rationale for why there is any concern over subpart I. A number of pipeline operators supported AGA's comments.

2. MidAmerican noted that PHMSA says current requirements are adequate yet goes on to propose new requirements.

3. INGAA reported that its members commit to mitigating corrosion anomalies in accordance with ASME/ANSI B31.8S, both inside and outside HCAs. INGAA argued that enhanced external corrosion management methods, such as close interval surveys and post-construction coating surveys, should not be required singularly and arbitrarily by new prescriptive regulations, since these methods can be redundant or inferior when combined with other assessment techniques. INGAA argued that these methods should continue to be used by operators on a threat-specific basis, as is currently practiced under performance-based regulations and consensus-based IM programs. A number of pipeline operators supported INGAA's comments.

4. Chevron argued that more prescriptive requirements are unnecessary, noting that current regulations allow operators the flexibility to select the most effective corrosion control method for the specific corrosion threats to a pipeline segment.

5. MidAmerican reported that it has never identified internal corrosion on its pipeline system and prescriptive requirements related to that threat would divert resources. MidAmerican opined that subpart I provides an adequate level of safety and any changes in that subpart should be approached carefully because they could be beneficial or detrimental for reducing risk. MidAmerican further noted that NACE SP0204 and ASME/ANSI B31.8S provide adequate guidance in this area.

6. TransCanada suggested that PHMSA incorporate the new SCC management provision in ASME/ANSI B31.8S as the basis for identifying and mitigating SCC and be responsive to further enhancements. TransCanada also suggested that the best way to manage corrosion anomalies is through assessments.

7. Dominion East Ohio opined that existing regulations in this area are adequate.

8. NAPSR urged PHMSA to establish or adopt standards or procedures, through a rulemaking proceeding, for improving the methods of preventing, detecting, assessing, and remediating stress corrosion cracking. NAPSR also suggested that PHMSA consider additional requirements to perform periodic coating surveys at compressor discharges and other high-temperature areas potentially susceptible to SCC and develop a training module for pipeline operators and federal and state inspectors that would include the identification of potential areas of SCC, detecting, assessing and remediating SCC.

9. A private citizen reported that his analysis of data from over 5000 lightning strikes indicates that cathodic protection systems make pipelines a frequent target for lightning.

10. A private citizen suggested that enforcement of cathodic protection requirements be strengthened, stating that the number of enforcement actions indicates that operators are not operating or maintaining CP as required.

11. A private citizen suggested that in-line inspection (ILI) capable of detecting seam issues should be required for pipe susceptible to selective seam weld corrosion, since pressure testing is not adequate to detect non-leak anomalies. If not possible, the commenter would require that this pipe be replaced.

Response

PHMSA appreciates the information provided by the commenters. In light of the contributing factors to the San Bruno incident, including PG&E's reliance on direct assessment under circumstances for which direct assessment was not effective, and the incident in Marshall, Michigan, where fracture features were consistent with stress corrosion cracking, PHMSA believes that more specific measures are needed to address both stress corrosion cracking and selective seam weld corrosion. Based on lessons learned from incident investigations, such as the 2012 incident in Sissonville, West Virginia and the 2007 incident in Delhi, Louisiana, and improved capabilities of corrosion evaluation tools and methods, PHMSA believes that more specific minimum requirements are needed for control of both internal and external corrosion. In addition, cathodic protection is a well-established corrosion control tool, and PHMSA believes the benefits of cathodic protection outweigh any potential risks. Therefore, PHMSA proposes several

enhancements to subpart I for corrosion control and subparts M and O for assessment, including specific requirements to address stress corrosion cracking and selective seam weld corrosion, and enhanced corrosion control measures for HCAs, which are discussed in more detail in response to specific questions, below.

Comments Submitted for Questions in Topic I

I.1. Should PHMSA revise subpart I to provide additional specificity to requirements that are now presented in general terms? If so, which sections should be revised? What standards exist from which to draw more specific requirements?

1. INGAA and a number of pipeline operators commented that adding prescriptive requirements would be disruptive to operators, noting PHMSA has acknowledged the effectiveness of performance-based elements of the current requirements.

2. The AGA, the GPTC, the Texas Pipeline Association, the Texas Oil & Gas Association, and numerous pipeline operators questioned the need to amend subpart I. AGA noted that this is one of the more prescriptive sections of the code and has a 40-year history of demonstrated effectiveness.

3. Ameren Illinois opined it is not necessary to revise subpart I, because integrity management regulations require operators to identify threats and to manage them.

4. MidAmerican opposed more specific requirements for corrosion control, noting that there is wide diversity among pipelines and it is unlikely that a single set of specific requirements would apply effectively to all pipelines. MidAmerican suggested that additional specific requirements must be tailored to a wide range of pipeline configurations to be of any value.

5. Northern Natural Gas reported that IM results demonstrate that corrosion has been adequately addressed on its pipeline system.

6. Paiute and Southwest Gas noted that subpart I is one of the most prescriptive sections of the code, subpart O provides an additional layer of regulation, and NACE standards are robust and incorporated by reference.

7. Panhandle Energy commented that existing performance based regulations require the pipeline operator to establish procedures to determine the adequacy of CP monitoring locations and appropriate remediation schedules based on circumstances that are unique to each pipeline. Panhandle observed that PHMSA appears to be attempting to establish ''One Size Fits All'' prescriptive requirements and opined that such changes would have no positive effect on safety and may be detrimental.

8. Accufacts observed that too many pipeline operators are assuming that IM assessments can replace subpart I requirements when the intent was that the regulations work in conjunction with one another. Accufacts suggested that prescriptive regulation is needed to avoid serious misapplication of the IM section and to assure that subpart I regulations are implemented to keep corrosion under control.

9. Panhandle observed that the ANPRM states that ''prompt'' as used in § 192.465(d) is not defined, and does not recognize the definition of ''prompt remedial action'' outlined in the 1989 Office of Pipeline Safety's Operation and Enforcement Manual. Panhandle noted that the enforcement guidance requires PHMSA to evaluate the circumstances and provide rationale for any determination of ''unreasonable delay'' in any enforcement action associated with § 192.465(d). Panhandle observed that such evaluations are inherent in the enforcement of performance-based regulations and stand in sharp contrast to the ''check-box'' enforcement mentality of prescriptive regulations. Panhandle complained that the language of the ANPRM contradicts more than 20 years of enforcement history. Panhandle interpreted the ANPRM to mean that PHMSA has no authority to interpret part 192 other than through rulemaking.

10. An anonymous commenter suggested that PHMSA delete the requirement regarding 300 mV pipe-to-soil reading shift and adopt NACE SP0169.

11. The California Public Utilities Commission suggested that PHMSA consider modifying acceptance criteria to be based on instant-off readings, arguing that this would provide improved specificity concerning IR drop.

Response to Question I.1 Comments

PHMSA appreciates the information provided by the commenters. The majority of industry comments do not support revising subpart I to provide additional specificity to requirements. However, for the reasons discussed in this NPRM, PHMSA believes that certain regulations can be improved to better address issues that experience has shown can be important to protecting pipelines from corrosion damage, and that prudent operators currently implement. Therefore, PHMSA proposes to amend subparts G and I to: (1) Enhance requirements for electrical surveys (*i.e.,* close interval surveys); (2) require post construction surveys for coating damage; (3) require interference current surveys; (4) add more explicit requirements for internal corrosion control; and (5) revise Appendix D to better align with the criteria for cathodic protection in NACE SP0169. Included in these changes is a new definition of the terms ''electrical survey'' and ''close interval survey.'' To conform to the revised definition of ''electrical survey,'' the use of that term in subpart O would be replaced with ''indirect assessment'' to accommodate other techniques in addition to close-interval surveys.

I.2. Should PHMSA prescribe additional requirements for post-construction surveys for coating damage or to determine the adequacy of CP? If so, what factors should be addressed e.g., pipeline operating temperatures, coating types, etc.)?

1. INGAA and a number of pipeline operators argued that post-construction surveys are of limited use, arguing that they can identify damaged coating but not necessarily areas where SCC can occur.

2. AGA, supported by a number of its pipeline operator members, opined that existing requirements for post-construction surveys for coating damage and cathodic protection are sufficient and operators need flexibility to apply their resources to the highest risk areas.

3. GPTC agreed that existing regulations are sufficient, noting that operators are not experiencing difficulties related to post-construction surveys for coating damage or for determining the adequacy of CP.

4. Ameren Illinois noted that part 192 requirements are followed for the installation of new coated steel pipe and it will develop a process to deal with any problems that may be identified through integrity management. Atmos agreed, noting that post-construction baseline surveys are typically performed.

5. Kern River opined that corrosion control measures and mitigation are site specific and therefore universal conditions and mitigation requirements would likely be ineffective and inefficient. Performance-based criteria are the best way to ensure the integrity of the pipeline with the most innovative and effective solutions.

6. MidAmerican opposed new requirements, noting that areas of coating damage on pipelines are protected from corrosion by cathodic protection and existing requirements are adequate in this area.

7. NACE concluded that current regulations have proven adequate and

noted that PHMSA acknowledges in the ANPRM that ''[T]hese requirements have proven effective in minimizing the occurrence of incidents caused by gas transmission pipeline corrosion.''

8. Paiute and Southwest Gas opined that current requirements for coatings (§ 192.461) and cathodic protection (§ 192.463) are sufficient.

9. Northern Natural Gas stated that no new requirements are needed, observing that it takes action when CP surveys indicate a concern.

10. Panhandle argued that the proposed requirement for post construction coating does not address the cause of coating damage during construction and INGAA best practices have proven to be an effective means to provide pipeline safety, affording flexibility and recognizing the inherent limitations of coating surveys. Panhandle observed that PHMSA's requirements for the investigation of anomalies found during post construction coating surveys on alternate MAOP lines are overly conservative, waste resources, do not enhance pipeline safety, and should not be considered for use in any proposed rulemaking. Panhandle further recommended that any proposed regulations related to pipeline temperature should not use the 120 degrees Fahrenheit value used in § 192.620, since studies have demonstrated pipeline coatings can withstand temperatures up to 150 degrees. Panhandle further argued that industry experience verifies that the vast majority of coating holidays associated with pipeline construction are not an integrity threat when cathodic protection is applied to the pipeline. It also suggested that verification of pipeline integrity through ILI or pressure testing better utilizes resources than excavation and repair of pinholes in pipeline coating systems.

11. Panhandle observed that, from its experience with over 900 completed excavations, the coating anomaly ranking system of NACE SP0502 is extremely conservative and should only be used as part of the ECDA process.

12. Texas Pipeline Association and Texas Oil & Gas Association suggested that PHMSA should consider requiring close interval surveys at 5-year intervals.

13. TransCanada noted that enhanced external corrosion management methods, such as close interval surveys and post construction coating surveys, have proven effective in helping identify and mitigate certain corrosion damage conditions. TransCanada argued, however, that these methods should not be required singularly and arbitrarily by new prescriptive requirements, as they can be redundant or inferior when combined with other assessment techniques.

14. Pipeline Safety Trust suggested that additional post-construction surveying should be required to identify damage to or weakness in coating and to ensure the integrity of CP.

15. An anonymous commenter suggested that PHMSA require close interval survey before energizing new CP components, after backfill has settled, noting that this would ensure test stations are located in areas that will assure adequate protection.

16. The Commissioners of Wyoming County Pennsylvania recommended that PHMSA review operator practices and codify the ''best practices'' in this area.

Response to Question I.2 Comments

PHMSA appreciates the information provided by the commenters. The majority of industry comments do not support revising subpart I to prescribe additional requirements for post-construction surveys for coating damage or to determine the adequacy of CP. However, as detailed in the ANPRM, experience has shown that construction activities can damage coating and that identifying and remediating this damage can help protect pipeline integrity. PHMSA does agree that prescriptive practices for conducting coating surveys, as well as the criteria for remediation and other responses to indications of coating damage, are not always appropriate because coating damage is case-specific. Therefore, PHMSA proposes to add a requirement that each coating be assessed to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG) and damage be remediated if damage is discovered. In addition, for HCA segments, PHMSA proposes enhanced preventive and mitigative measures and repair criteria for repair of coating with a voltage drop classified as moderate or severe.

I.3. Should PHMSA require periodic interference current surveys? If so, to which pipelines should this requirement apply and what acceptance criteria should be used?

1. INGAA and a number of pipeline operators recommended that PHMSA not establish new requirements in this area without discussing the topic with operators first. INGAA pointed out that guidance already exists in the form of Advisory Bulletin ADB–03–06 and NACE SP0169.

2. Kern River opposed new requirements for periodic surveys, arguing that §§ 192.465, 192.467, and 192.473 adequately address the concerns.

3. Ameren Illinois also opposed new requirements. Ameren reported that it conducts testing annually at sites where stray currents are expected and noted that integrity management regulations already require operators to identify and address threats.

4. NACE International suggested that current regulations are adequate and have served the public interest. NACE noted operators are currently taking action to identify interference currents and protect their pipelines, and it has provided guidance through standards and technical papers.

5. Atmos noted that interference surveys would be a part of an investigation into cathodic protection systems that do not provide minimum levels of protection. Operators are already required to maintain minimum levels of protection.

6. Northern Natural Gas reported that it conducts additional surveys when issues are discovered during periodic maintenance, when new foreign line crossing are installed, or for new construction, but opposed new requirements in this area.

7. Paiute and Southwest Gas opposed new requirements, noting that operators should have the flexibility to allocate their resources in a manner that best suits their system.

8. Panhandle opposed new requirements, noting that existing performance-based regulations have proven adequate to address the threat of stray currents. Panhandle commented that the gas pipeline industry recognized and reacted to the threat of AC interference decades prior to the ANPRM, and suggested that the lack of justification from PHMSA on this issue is a strong indicator that industry has reacted appropriately to integrity threats in accordance with the requirements of § 192.473. Panhandle noted that interference currents have been addressed in several industry standards and publications. In particular, Section 9, *Control of Interference Currents,* of NACE SP0169, *Control of External Corrosion on Underground of Submerged Metallic Piping Systems,* provides guidance for the detection and mitigation of interference currents.

9. Texas Pipeline Association and Texas Oil & Gas Association stated that current regulations are sufficient; however, if new regulations are promulgated, the associations recommended that PHMSA use the liquid pipeline requirement for periodic interference surveys and be applicable only to foreign line crossings and

pipelines near large DC-powered equipment.

10. An anonymous commenter stated that new regulations are not needed, as most operators will conduct surveys on their own, generally when pipe-to-soil readings drop.

Response to Question I.3 Comments

PHMSA appreciates the information provided by the commenters. Industry comments do not support revising subpart I to require periodic interference current surveys. However, as detailed in the ANPRM, pipelines are often routed near, in parallel with, or in common rights-of-way with, electrical transmission lines or other pipelines that can induce interference currents, which, in turn, can induce corrosion. Recent incidents on pipelines operated by Kern River and Center Point are examples of incidents this requirement seeks to prevent. Section 192.473 currently requires that operators of pipelines subject to stray currents have a program to minimize detrimental effects but does not require surveys, mitigation, or provide any criteria for determining the adequacy of such programs. Therefore, PHMSA proposes to add a requirement that the continuing program to minimize the detrimental effects of stray currents must include: (1) Interference surveys to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected; (2) analysis of the results of the survey; and (3) prompt remediation of problems after completing the survey to protect the pipeline segment from deleterious current. For HCA segments, PHMSA proposes to address this in enhanced preventive and mitigative measures, and to include performance criteria.

I.4. Should PHMSA require additional measures to prevent internal corrosion in gas transmission pipelines? If so, what measures should be required?

1. INGAA, AGA, GPTC, and numerous pipeline operators contended that existing requirements are adequate to manage internal corrosion. INGAA noted that subparts I and O include requirements for controlling internal corrosion and assessments are being performed on almost all gas transmission lines. INGAA further commented that controlling gas quality is most important.

2. Ameren Illinois opposed new requirements addressing internal corrosion, noting that § 192.475 addresses the topic and subpart O requires operators to respond to risks that are identified.

3. Kern River and Northern Natural Gas opposed new requirements, noting that industry data show IC is a minor threat to natural gas transmission pipelines. Kern River commented that ASME/ANSI B31.8S, Appendix A2, covers the analysis of gas constituents. Northern monitors gas quality and takes corrective action as needed.

4. MidAmerican opposed new requirements, commenting that internal corrosion is a regional problem and does not occur in many areas of the country. MidAmerican requested that current integrity management regulations be revised to eliminate the need to conduct internal corrosion direct assessment when internal corrosion is not a threat.

5. NACE International opined that current regulations in subpart I are adequate to address internal corrosion, and PHMSA's proposed prescriptive requirements are not feasible.

6. Panhandle observed that requirements to minimize the potential for internal corrosion in gas transmission pipelines are included in §§ 192.475, 192.476, and 192.477. In addition, OPS issued ADB–00–02 requiring pipeline operators to review their internal corrosion monitoring programs and operation. IM regulations in subpart O require integrity management assessments that address the threat of internal corrosion. INGAA members report that completion of baseline assessments required by subpart O will result in the assessment of more than half of the gas transmission pipeline mileage in the U.S. Panhandle commented that several proposed prescriptive internal corrosion requirements provided in the ANPRM are not feasible and noted that liquids tend to accumulate in low spots that typically are not accessible for sampling. Panhandle opined that vigilant enforcement of gas quality standards is the most essential component of an internal corrosion control program.

7. Texas Pipeline Association and Texas Oil & Gas Association argued that no benefit would be gained by additional requirements in this area. The associations observed that internal corrosion threats are highly localized and monitoring and remediation efforts must be customized for local conditions.

8. IUB noted that not all pipelines are susceptible to internal corrosion and commented that operators and state inspection personnel should not be unduly burdened by additional measures when problems do not exist.

9. An anonymous commenter suggested that PHMSA require each operator to have a subject matter expert well qualified in internal corrosion, arguing that most operators currently rely on third-party contractors.

Response to Question I.4 Comments

PHMSA appreciates the information provided by the commenters. The majority of industry comments do not support revising subpart I to require additional measures to prevent internal corrosion in gas transmission pipelines. However, the current requirements for internal corrosion control are non-specific and PHMSA believes that there is benefit in enhancing the current internal corrosion control requirements to establish a more effective minimum standard for internal corrosion management. Therefore, PHMSA proposes to add a requirement that each operator develop and implement a program to monitor for and mitigate the presence of, deleterious gas stream constituents and that the program be reviewed at least semi-annually. For HCA segments, PHMSA proposes to address this in enhanced preventive and mitigative measures to include objective performance criteria.

I.5. Should PHMSA prescribe practices or standards that address prevention, detection, assessment, and remediation of SCC on gas transmission pipeline systems? Should PHMSA require additional surveys or shorter IM survey internals based upon the pipeline operating temperatures and coating types?

1. INGAA and a number of pipeline operators recommended that PHMSA avoid prescriptive requirements for the prevention, detection, assessment, and remediation of SCC. The commenters noted that SCC varies from pipeline to pipeline and suggested that threat management should be through a framework of processes and decision making that can tailor threat management to the requirements of each pipeline.

2. AGA and a number of its pipeline operators also objected to new requirements in this area, noting that numerous industry documents exist that provide guidance to address SCC.

3. Panhandle suggested that PHMSA avoid prescriptive standards for the prevention, detection, assessment, and remediation of SCC on gas transmission systems given the complex and variable nature of the factors contributing to the formation and growth of SCC, arguing performance-based standards allow operators the maximum flexibility to develop and apply situational techniques for detecting, assessing, and remediating this threat. Panhandle noted that multiple standards and publications are available to address internal corrosion and that the Pipeline

Research Council International (PRCI) has ongoing research in this area. Panhandle expressed the view that voluntary use of performance based standards, allowing operator flexibility in detecting, assessing and remediating this threat, will ensure that the methods used in managing these types of anomalies continue to improve.

4. GPTC, Ameren Illinois, Atmos, Paiute, and Southwest Gas argued that existing regulations are sufficient and noted that there are numerous industry documents that provide additional guidance for addressing SCC.

5. TransCanada suggested that PHMSA adopt the current version of ASME/ANSI B31.8S.

6. The Commissioners of Wyoming County Pennsylvania opined that it is reasonable for PHMSA to prescribe practices or standards that address prevention, detection, assessment and remediation of SCC on transmission and gas gathering lines, including those in Class 1 locations. The Commissioners argued that it is important to address this aspect of corrosion given aging of existing pipelines and the significant number of new pipelines.

7. Air Products and Chemicals argued that operators should not be required to undertake SCC prevention, detection, assessment and remediation activities where a pipeline does not meet the B31.8S criterion for SCC. Air Products further commented that it is important that PHMSA's regulations and standards reflect the threshold concept of susceptibility to SCC, and that a pipeline that does not meet the B31.8S criteria for SCC risk should not be required to undertake SCC prevention, detection, assessment, and remediation activities.

8. NACE International stated that overly prescriptive rules can supplant sound engineering judgment and prevent innovation and the development of new technologies.

9. Northern Natural Gas argued that the current regulations and industry standards provide adequate guidance and that the assessment criteria address operating temperature and coating type. Northern Natural Gas noted that operating temperature is addressed in PHMSA Gas FAQ 223 and that the reassessment interval should be determined by the results of the integrity assessment performed pursuant to ASME B31.8S.

10. MidAmerican pointed out that these concerns are addressed in the pre-assessment phase of direct assessment and adequately covered in ASME/ANSI B31.8S.

11. Texas Pipeline Association and Texas Oil & Gas Association suggested that additional regulations related to SCC could prove beneficial. At the same time, the associations recommended that PHMSA not require additional surveys or shorter intervals, arguing that the current regulations are based on sound engineering practices.

12. A private citizen commented that SCC should be addressed as part of a comprehensive corrosion control program.

13. An anonymous commenter noted that a reliable survey technique for SCC does not now exist and suggested that PHMSA require shorter assessment intervals for pipelines with a history of SCC.

14. INGAA argued that pipe temperature and coating are not sufficient to identify SCC. INGAA contended that ASME/ANSI B31.8S adequately covers prevention, detection, assessments, and remediation of SCC and criteria to capture all pipe potentially susceptible to SCC would be overly conservative. A number of pipeline operators supported INGAA's comments.

15. NACE International opined that there are too many factors involved, and they are too interrelated and location-specific, to allow prescribing an optimal assessment interval for SCC.

Response to Question I.5 Comments

PHMSA appreciates the information provided by the commenters. The majority of industry comments do not support new requirements for the prevention, detection, assessment, and remediation of SCC. PHMSA recognizes that SCC is an important safety concern, but does not believe the current methods for managing SCC anomalies supports prescribing a detailed SCC management approach that would be effective for all operators. PHMSA does not propose to amend subpart I to prescribe an SCC management plan at this time. PHMSA will continue to study this issue and support ongoing research. PHMSA plans to hold a public forum on the development of SCC standards in the future. Once that process is complete, PHMSA will consider new minimum safety standards for managing the threat of SCC. However, under topics C and G, above, PHMSA does propose to include more specific requirements for conducting integrity assessments for the threat of SCC and for enhancing the HCA and non-HCA repair criteria to address SCC.

I.6. Does the NACE SP0204–2008 (formerly RP0204) Standard ''Stress Corrosion Cracking Direct Assessment Methodology'' address the full life cycle concerns associated with SCC? Should PHMSA consider this, or any other standards to govern the SCC assessment and remediation procedures? Do these standards vary significantly from existing practices associated with SCC assessments?

1. INGAA and a number of pipeline operators stated that NACE SP0204 does not address the full life cycle of concerns of SCC. INGAA added that SP0204, along with ASME/ANSI B31.8S, NACE publication 35103, STP–TP–011, and Canadian recommended practices, do cover the full life cycle concerns.

2. NACE International reported that its standard (SP0204) does not address the full life cycle concerns of SCC.

3. GPTC noted that existing regulations and standards address SCC concerns and commented that it is not clear what is meant by ''full life cycle concerns.''

4. Ameren Illinois argued that full life cycle concerns are addressed in the pre-assessment phase of stress corrosion cracking direct assessment (SCCDA) and new prescriptive requirements are not needed.

5. Northern Natural Gas commented that ASME/ANSI B31.8S should be used in conjunction with NACE SP0204.

6. Panhandle reported that SCCDA was never intended to address full life cycle management for SCC. The standard does not address aspects such as the formation or nucleation of cracks or calculations to assess the severity of cracks. Panhandle opined that the collective body of SCC research does address the full life cycle, but cautioned the full body of knowledge of all documents must be considered as some may be dated and do not reflect current knowledge on SCC management.

7. An anonymous commenter suggested that NACE SP0204 does not address full life cycle concerns, noting that SCC has been found in circumstances where the standard would suggest it should not be expected.

Response to Question I.6 Comments

PHMSA appreciates the information provided by the commenters and agrees that sufficient information is not available at this time to specify prescriptive standards for SCC management. See the response to comments received on question I.5.

I.7. Are there statistics available on the extent to which the application of the NACE Standard, or other standards, have affected the number of SCC indications operators have detected on their pipelines and the number of SCC-related pipeline failures? Are statistics available that identify the number of SCC occurrences that have been

discovered at locations that meet the screening criteria in the NACE standard and at locations that do not meet the screening criteria?

1. INGAA, GPTC, Texas Pipeline Association, Texas Oil & Gas Association, and numerous pipeline operators reported that no data has been collected on the application of any current standard. INGAA added that available statistics indicate that the annual number of failures due to SCC is generally decreasing and noted that a high percentage of in-service failures, failures during hydro testing, and instances where SCC cracks greater than 10 percent were found during excavations have met the screening criteria of ASME/ANSI B31.8S (which are identical to the NACE criteria).

2. Northern Natural Gas reported that it has found one instance of SCC and no segments were identified subject to similar circumstances.

Response to Question I.7 Comments

PHMSA appreciates the information provided by the commenters and agrees that sufficient information is not available at this time to specify prescriptive standards for SCC management. PHMSA will be studying this issue and soliciting further input from stakeholders in the future. See the response to comments received on question I.5.

I.8. If new standards were to be developed for SCC, what key issues should they address? Should they be voluntary?

1. NACE International suggested that existing standards should be updated and improved rather than developing new standards, noting that such updating is as normal part of the standards process.

2. INGAA and a number of its pipeline operators supported the development of voluntary standards to cover detection, assessment, mitigation, periodic assessment, and evaluation of effectiveness.

3. Panhandle supported the development of industry standards to manage SCC but does not believe that such a document can be completed until the gaps in the understanding of SCC have been addressed.

4. GPTC, Ameren Illinois, and Northern Natural Gas opined that the combination of ASME/ANSI B31.8S and ASME STP–PT–011 provide adequate guidance.

5. Atmos recommended that further investigation be required if SCC outside of the criterion specified in NACE SP0204–2008 is found. Atmos stated that any new standards that are developed should be voluntary so that operators have additional methodologies available for mitigating the threat of SCC as currently required by § 192.929.

6. Texas Pipeline Association and Texas Oil & Gas Association recommended any new standards for SCC apply only to Class 1 locations, based on their conclusion that pipe designed for Class 2 conditions (and above) is not susceptible to SCC.

Response to Question I.8 Comments

PHMSA appreciates the information provided by the commenters and agrees that sufficient information is not available at this time to specify prescriptive standards for SCC management. PHMSA will be studying this issue and soliciting further input from stakeholders in the future. See the response to comments received on question I.5.

I.9. Does the definition of corrosive gas need to clarify that other constituents of a gas stream (e.g., water, carbon dioxide, sulfur and hydrogen sulfide) could make the gas stream corrosive? If so, why does it need to be clarified?

1. INGAA, supported by a number of its pipeline operators, opined that the existing regulations are adequate, and commented that prescriptive limits, such as those in § 192.620, would not be as effective in reducing the potential for internal corrosion.

2. GPTC recommended that § 192.476 be revised to reflect only those liquids that act as an electrolyte (*i.e.,* water).

3. AGA sees no need to clarify the definition and noted that the stated constituents pose no threat if water is not present.

4. Atmos, Paiute, and Southwest Gas noted that gas tariffs maintain gas quality and water must be present with the constituents listed to produce a corrosive gas stream. Paiute opined that § 192.929 and ASME/ANSI B31.8S are sufficient.

5. NACE International expressed uncertainty as to why the definition needs to be clarified. NACE also noted that there are more factors than those listed in the question that affect the corrosiveness of a gas stream.

6. MidAmerican, Ameren Illinois, and Northern Natural Gas noted that ASME/ANSI B31.8S requires analysis of gas constituents and argued that operators know what constitutes a corrosive gas stream. The operators do not believe the definition needs to be changed.

7. Kern River suggested that the definition should be changed, noting that water must be present, in addition to the listed constituents, to make a gas stream corrosive.

8. Texas Pipeline Association and Texas Oil & Gas Association suggested no change to the definition is needed, since operators understand the listed constituents, when combined with water, can cause internal corrosion.

9. An anonymous commenter suggested that PHMSA not attempt to list constituents that could make a gas stream corrosive, arguing there are too many scenarios to cover. The commenter noted that the issue is not simple: H_2O w/o free O_2, or CO_2 or sulfur alone are not corrosive.

Response to Question I.9 Comments

PHMSA appreciates the information provided by commenters, and consistent with the majority of comments, PHMSA does not propose to revise the definition of corrosive gas at this time. However, PHMSA does propose to clarify the regulations by listing examples of constituents that are potentially corrosive, and to propose objective performance criteria for monitoring gas stream contaminants for HCA segments.

I.10. Should PHMSA prescribe for HCAs and non-HCAs external corrosion control survey timing intervals for close interval surveys that are used to determine the effectiveness of CP?

1. INGAA, supported by a number of pipeline operators, suggested that safety would be best served by following a risk-based approach to determine intervals for corrosion control or close interval surveys, arguing that prescriptive requirements applicable to all pipelines would divert safety resources from other high-risk tasks.

2. AGA, GPTC, and a number of pipeline operators argued that there is no reason for PHMSA to specify timing of close interval surveys, contending that the current subpart I requirements have proven to be successful and the use of CIS as an indirect assessment tool is built into NACE SP0502.

3. Ameren Illinois opposed the prescribed intervals for close interval surveys, arguing that § 192.463 and 192.465 are adequate. In addition, Ameren noted that § 192.917(e)(5) requires an operator to evaluate and remediate corrosion in both covered and non-covered segments when corrosion is found.

4. Atmos opposed required timing for close interval surveys, arguing that CIS is just one tool that can be used to determine the effectiveness of CP.

5. MidAmerican expressed its conclusion that establishing required timing intervals for close interval surveys would not be beneficial. MidAmerican noted that specific pipeline characteristics need to be taken

into consideration in establishing inspection intervals.

6. Paiute and Southwest Gas opposed required periodicity for close interval surveys, arguing that NACE SP0207 provides adequate guidance.

7. Northern Natural Gas commented that PHMSA should not prescribe external corrosion control survey intervals for close interval surveys, noting that its integrity management program demonstrates that external corrosion is being managed effectively.

8. Texas Pipeline Association and Texas Oil & Gas Association argued that industry experience demonstrates existing requirements are adequate.

9. An anonymous commenter suggested that specified periodicity for close interval surveys could have benefit, especially where a history of external corrosion exists.

Response to Question I.10 Comments

PHMSA appreciates the information provided by the commenters. Recent experience, including the December 2012 explosion near Sissonville, WV and the 2007 incident near Delhi, LA, underscores the need to be more attentive to external corrosion mitigation activities. PHMSA proposes to enhance the requirements of subpart I to require that operators conduct close-interval surveys if annual test station readings indicate that cathodic protection is below the level of protection required in subpart I, or to restore adequate corrosion control. For HCA segments, PHMSA proposes to address these requirements in enhanced preventive and mitigative measures, to include an objective timeframe for restoration of deficient cathodic protection.

I.11. Should PHMSA prescribe for HCAs and non-HCAs corrosion control measures with clearly defined conditions and appropriate mitigation efforts? If so, why?

1. INGAA stated it does not believe it is feasible to develop prescriptive measures that identify necessary and sufficient monitoring and mitigation efforts in all environments. A number of pipeline operators supported INGAA's comments.

2. AGA and a number of its operator members expressed their conclusion that the requirements of subpart I are sufficient, noting that they address HCA and non HCA alike.

3. GPTC commented that the question does not make clear why additional measures should be prescribed given that operators have been successfully mitigating corrosion deficiencies for many years.

4. Ameren Illinois expressed its conclusion that the science of corrosion mitigation is sufficiently advanced and appropriate mitigation measures are well known. Atmos, Paiute, and Southwest Gas agreed, concluding that subpart I is sufficient when implemented properly by appropriately trained and qualified personnel.

5. MidAmerican opposed new requirements, arguing that current regulations address all practical mitigation efforts.

6. Texas Pipeline Association and Texas Oil & Gas Association suggested that more time should be allowed before additional prescriptive requirements on cathodic protection are considered, noting that corrosion leaks are trending downward.

7. The Commissioners of Wyoming County Pennsylvania suggested that it is reasonable that PHMSA prescribe corrosion control measures for HCAs and non-HCAs with clearly defined conditions and appropriate mitigation efforts. They cited information from NACE indicating that 25 percent of all accidents are caused by corrosion and these accidents account for 36 percent of all accident damage. The Commissioners noted that gathering lines in the Marcellus Shale area have diameters and pressures similar to transmission lines and should be subjected to the same requirements.

8. An anonymous commenter recommended that PHMSA not prescribe specific measures.

Response to Question I.11 Comments

PHMSA appreciates the comments provided, and consistent with the majority of comments, does not propose additional regulatory changes at this time, other than to prescribe measures to promptly restore cathodic protection, as discussed in the response to comments received for question I.10.

PHMSA is interested in the extent to which operators have implemented Canadian Energy Pipeline Association (CEPA) SCC, Recommended Practices 2nd Edition, 2007, and what the results have been.

I.12. Are there statistics available on the extent to which gas transmission pipeline operators apply the Canadian Energy Pipeline Association (CEPA) practices?

I.13. Are there statistics available that compare the number of SCC indications detected and SCC-related failures between operators applying the CEPA practices and those applying other SCC standards or practices?

1. INGAA reported that most major operators in North America have adopted threat management closely aligned to CEPA standards, but that no specific data exist that correlate the use of CEPA methods to anomaly detection. INGAA reported a Joint Industry Project (JIP) study that shows that applying NACE SP0204, ASME/ANSI B31.8S, CEPA, and other standards has led to a significant reduction in in-service failures. Numerous pipeline operators supported INGAA comments.

2. AGA, supported by a number of its pipeline operator members, questioned why a discussion of CEPA standards was included in the ANPRM. AGA suggested that CEPA practices are well suited to Canadian infrastructure, but not necessarily applicable in the United States and noted that CEPA is not often discussed by Canadian members at AGA meetings.

3. GPTC expressed that its membership has little knowledge of CEPA standards, commented that it is not clear what is meant by full life cycle concerns, and argued that existing standards and regulations adequately address SCC concerns. GPTC is not aware of any data correlating the efficacy of CEPA to other standards.

4. Paiute and Southwest Gas reported that they have not implemented CEPA standards.

Response to Questions I.12 and I.13 Comments

PHMSA appreciates the information provided by the commenters. PHMSA acknowledges the comments provided on the use of the CEPA SCC Recommended Practice and will consider that standard in its study of comprehensive safety requirements for SCC.

I.14. Do the CEPA practices address the full life cycle concerns associated with SCC? If not, which are not addressed?

1. INGAA reported its conclusion that CEPA standards address full life cycle concerns for near-neutral SCC. Many management techniques in CEPA standards are also applicable to high-pH SCC, but the two are not identical. Several pipeline operators supported INGAA's comments.

2. Texas Pipeline Association and Texas Oil & Gas Association expressed their conclusion that CEPA standards address the full life cycle concerns of SCC.

Response to Question I.14 Comments

PHMSA appreciates the information provided by the commenters. PHMSA acknowledges the comments provided on the use of the CEPA SCC Recommended Practice and will consider that standard in its study of

comprehensive safety requirements for SCC.

I.15. Are there additional industry practices that address SCC?

1. INGAA, supported by a number of its pipeline operator members, reported that there are no related European standards and Australia has a standard similar to ASME/ANSI B31.8S. INGAA noted that SCC failures of pipelines installed since 1980 are rare and observed that quality coating and cathodic protection are the most effective means of preventing SCC.

2. GPTC stated that NACE SP0204 and 35103, ASME/ANSI B31.8S, and GPTC guide material address SCC. Paiute and Southwest Gas agreed that NACE standards and GPTC provide relevant guidance.

3. AGA commented that it does not have the statistics available to advise whether or not additional requirements are needed to address SCC threats.

4. Atmos, Texas Pipeline Association and Texas Oil & Gas Association reported that they have no knowledge of other SCC standards or practices.

5. Northern Natural Gas cited ASME/ANSI B31.8S and ASME STP–PT–011.

Response to Question I.15 Comments

PHMSA appreciates the information provided by the commenters. PHMSA acknowledges the comments provided on the standards, and will consider these standards in its study of comprehensive safety requirements for SCC.

I.16. Are there statistics available on the extent to which various tools and methods can accurately and reliably detect and determine the severity of SCC?

1. INGAA noted that the measurement of ILI crack detection tool performance is an ongoing research activity, both within JIP Phase II and within the Pipeline Research Council International, which is actively supported by the tool vendors and the pipeline operators. Several issues regarding the acquisition and interpretation of information need to be standardized by the practitioners before a clear picture can emerge. The implications of tool tolerance on predicted failure pressure are being studied in the JIP Phase II.

2. GPTC, Atmos, Paiute, Southwest Gas, and an anonymous commenter reported that they are unaware of any relevant statistics.

3. Northern Natural Gas reported that it has used electro-magnetic acoustic transducer (EMAT) ILI with some success.

4. Panhandle commented that magnetic particle inspection (MPI) is effective at locating surface-breaking linear indications, a subset of SCC. Furthermore, abrasive wheel grinding in conjunction with MPI is an effective method to size the length and depth of surface-breaking linear indications, limited by the amount of metal that can be removed from in-service pipelines. Panhandle noted that PRCI research indicates that laser UT techniques can effectively locate and size SCC, but this method is relatively new and Panhandle has no experience with its use. Panhandle also reported that the use of EMAT has yet to be acknowledged as a replacement for hydrostatic testing but it is being evaluated in Phase II of the SCC Joint Industry Project (JIP); results of the study will be used to determine the path forward for EMAT technology.

5. Texas Pipeline Association and Texas Oil & Gas Association reported that they have no knowledge of relevant references other than the Baker study.

Response to Question I.16 Comments

PHMSA appreciates the information provided by the commenters and will consider this information in its study of comprehensive safety requirements for SCC.

I.17. Are tools or methods available to detect accurately and reliably the severity of SCC when it is associated with longitudinal pipe seams?

1. INGAA and a number of pipeline operators noted that detecting SCC close to a longitudinal seam is difficult and even harder near a girth weld. INGAA commented that developing tools to reliably detect and assess SCC near longitudinal seams is a continuing challenge.

2. GPTC reported that SCC tools are available; however, GPTC cautioned that the ability to accurately and reliably detect the severity of SCC associated with longitudinal seams is dependent on specific operating conditions.

3. Atmos commented that it knows of no tools that can accurately detect and estimate the severity of SCC near a longitudinal seam.

4. Paiute and Southwest Gas reported that tools are being developed but are, as of yet, not accurate at determining the severity of SCC associated with longitudinal seams.

5. Northern Natural Gas reported that it has used electro-magnetic acoustic transducer (EMAT) ILI with some success. Panhandle added that difficulties in using EMAT are further complicated when cracking is associated with a longitudinal seam.

6. Texas Pipeline Association and Texas Oil & Gas Association expressed their conclusion that the best methods to assess for SCC near longitudinal seams are pressure testing and EMAT, although they noted that some operators have had success with transverse flux ILI.

7. An anonymous commenter reported that new ILI tools exist but that analysts are not yet consistent in using them.

Response to Question I.17 Comments

PHMSA appreciates the information provided by the commenters and will consider this information in its study of comprehensive safety requirements for SCC.

I.18. Should PHMSA require that operators perform a critical analysis of all factors that influence SCC to determine if SCC is a credible threat for each pipeline segment? If so, why? What experience based indications have proven reliable in determining whether SCC could be present?

1. INGAA, supported by a number of pipeline operators, noted that operators are already required to perform an analysis to determine the likelihood of SCC. INGAA added that operators address the pipelines with the highest likelihood of SCC and apply lessons learned, as appropriate, to lower-likelihood pipelines.

2. Texas Pipeline Association and Texas Oil & Gas Association indicated that a requirement to perform a critical analysis for SCC is unnecessary, since guidance in ASME/ANSI B31.8S is sufficient. Northern Natural Gas also stated that additional requirements are unnecessary, noting that it conducted an analysis of critical factors affecting SCC and identified no new factors over those in B31.8S, Appendix 3.

3. Atmos stated that PHMSA's question was unclear whether to expand the threat of SCC to all pipeline segments or expand the requirements for investigating the presence of SCC within HCA segments? Atmos concluded that subpart O requirements provide a framework for operators to integrate data, rank risk, identify threats, and apply appropriate mitigative actions; additional requirements are not needed.

4. Texas Pipeline Association and Texas Oil & Gas Association suggested that PHMSA conduct a workshop to share industry experience with SCC.

Response to Question I.18 Comments

PHMSA appreciates the information provided by the commenters and will consider this information in its study of comprehensive safety requirements for SCC.

I.19. Should PHMSA require an integrity assessment using methods capable of detecting SCC whenever a credible threat of SCC is identified?

1. INGAA, Panhandle, Atmos, and Northern Natural Gas noted that subpart O already requires that all credible threats be identified and assessed. A number of pipeline operators supported INGAA's comments.

2. Texas Pipeline Association and Texas Oil & Gas Association also indicated that they read subpart O as requiring assessment using a method that can detect SCC if that threat is credible. The associations both added, however, that they would not object to making this requirement more explicit.

3. GPTC opined that existing regulations and standards are adequate to address SCC issues.

4. Southwest Gas opposed a new requirement, noting that § 192.929 and ASME/ANSI B31.8S are sufficient.

Response to Question I.19 Comments

PHMSA appreciates the information provided by the commenters and will consider this information in its study of comprehensive safety requirements for SCC. As indicated above in the response to comments received on question I.5, PHMSA proposes more explicit requirements for selection of appropriate methods for integrity assessments for SCC.

I.20. Should PHMSA require a periodic analysis of the effectiveness of operator corrosion management programs, which integrates information about CP, coating anomalies, in-line inspection data, corrosion coupon data, corrosion inhibitor usage, analysis of corrosion products, environmental and soil data, and any other pertinent information related to corrosion management? Should PHMSA require that operators periodically submit corrosion management performance metric data?

1. INGAA, Kern River, Paiute, and Southwest Gas commented that these issues are already addressed in subpart O, which requires operators to keep records, measure program effectiveness, continually evaluate and assess systems, integrate data, and show continual improvement. INGAA added that metrics bearing on the effectiveness of a corrosion control program are already among those required to be collected by ASME/ANSI B31.8S. These metrics are not required to be submitted, but are available for review during inspections. A number of pipeline operators supported INGAA's comments.

2. MidAmerican commented that subparts I and O include these requirements. Northern Natural Gas agreed that it manages these threats through O&M and IM activities.

3. Panhandle noted that subpart I requires operators to maintain effective corrosion control programs to mitigate the threat of corrosion and § 192.945 requires operators to measure, on a semi-annual basis, whether the integrity management program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting HCAs.

4. GPTC and AGA, supported by a number of its pipeline operator members, opposed requiring operators to submit corrosion management metrics. AGA noted that operators need flexibility to select the appropriate analysis methods and key performance indicators. Furthermore, operators review corrosion control program effectiveness, and plans of intrastate operators are reviewed by state commissions.

5. Ameren Illinois opposed new requirements, noting that subpart O already requires operators to identify and respond to risks.

6. Atmos questioned whether PHMSA is proposing to measure the effectiveness of corrosion management programs across all pipeline segments or to measure the effectiveness of corrosion management programs in HCA segments. Atmos added that the data points enumerated by PHMSA in this question would be difficult to gather on an operator's entire pipeline system.

7. Texas Pipeline Association and Texas Oil & Gas Association stated that they do not see a need for a requirement to periodically analyze the effectiveness of an operator's corrosion management program, arguing that existing requirements are sufficient.

8. Panhandle argued that the standardization of corrosion control efforts, as would be required for performance metric tracking, would require additional prescriptive requirements in subpart O. Panhandle does not believe that elimination of performance-based language is beneficial.

9. The Commissioners of Wyoming County Pennsylvania suggested that any communication between operators and PHMSA regarding corrosion management would be helpful in facilitating operator compliance and best practices.

10. Paiute and Southwest Gas reported that they opposed a requirement to report additional performance metrics absent a definition of how new data would be collected and used.

Response to Question I.20 Comments

PHMSA appreciates the information provided by the commenters. Following publication of the ANPRM, the NTSB issued recommendations in response to the San Bruno pipeline incident, including a specific recommendation (P–11–19) that PHMSA establish standards for evaluating effective program performance. PHMSA will evaluate standards for integration of pipeline corrosion data to enhance corrosion management performance as part of its response to that recommendation.

I.21. Are any further actions needed to address corrosion issues?

1. INGAA, supported by a number of its pipeline operator members, commented that continued study and evaluation of the root causes of the San Bruno explosion, documentation of findings, and communication of results are needed rather than additional prescriptive requirements.

2. AGA, GPTC, and a number of pipeline operators argued that no further action is needed, given that current methodologies adequately address corrosion issues and operators are subject to periodic audits by federal and state safety regulators.

3. Accufacts suggested that PHMSA needs to assure that IM programs are not solely relied upon to prevent corrosion failure.

4. Texas Pipeline Association and Texas Oil & Gas Association reported that they do not see any deficiencies necessitating new regulations.

Response to Question I.21 Comments

PHMSA appreciates the information provided by the commenters. As discussed above, PHMSA is proposing some enhanced measures for corrosion control in subpart I and subpart O.

I.22. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

J. Pipe Manufactured Using Longitudinal Weld Seams

The ANPRM requested comments regarding additional integrity management and pressure testing

requirements for pipe manufactured using longitudinal seam welding techniques that have not had a subpart J pressure test. Pipelines built since the regulations (49 CFR part 192) were implemented in early 1971 must be:

• Pressure tested after construction and prior to being placed into gas service in accordance with subpart J; and

• Manufactured in accordance with a referenced standard (most gas transmission pipe has been manufactured in accordance with American Petroleum Institute Standard 5L, 5LX or 5LS, ''Specification for Line Pipe'' (API 5L) referenced in 49 CFR part 192).

Many gas transmission pipelines built from the 1940's through 1970 were manufactured in accordance with API 5L, but may not have been pressure tested similar to a subpart J pressure test. For pipelines built prior to 1971, § 192.619(a) allows MAOP to be based on the highest 5-year operating pressure established prior to July 1, 1970, in lieu of a pressure test. Accordingly, some of this pre-existing pipe possesses variable characteristics throughout the longitudinal weld or pipe body.

As a result of 12 hazardous liquid pipeline failures that occurred during 1986 and 1987 involving pre-1970 ERW pipe, PHMSA issued an alert notice (ALN–88–01, January 28, 1988) to advise operators with pre-1970 ERW pipe of the 12 pipeline failures and the actions to take. Subsequent to this notice, one additional failure on a gas transmission pipeline, and eight additional failures on hazardous liquid pipelines occurred, which resulted in PHMSA issuing another alert notice (ALN–89–01, March 8, 1989) to advise operators of additional findings since the previous alert notice. These notices identified the fact that some failures appeared to be due to selective seam weld corrosion, but that other failures appeared to have resulted from flat growth of manufacturing defects in the ERW seam. In these notices, PHMSA specifically advised all gas transmission and hazardous liquid pipeline operators with pre-1970 ERW pipe to consider hydrostatic testing of affected pipelines, to avoid increasing a pipeline's long-standing operating pressure, to assure effectiveness of the CP system, and to conduct metallurgical exams in the event of an ERW seam failure.

Since 2002, there have been at least 22 reportable incidents on gas transmission pipeline caused by manufacturing or seam defects. In addition, recent high consequence incidents, including the 2009 failure in Palm City, Florida and the 2010 failure in San Bruno, California, have been caused by longitudinal seam failures.

The ANPRM listed questions for consideration and comment. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comment for Topic J

1. Texas Pipeline Association and Texas Oil & Gas Association suggested that seam issues are best addressed through inspection, detection, remediation, and monitoring, based on specific segments, not a one-size-fits-all requirement.

Response to General Comment for Topic J

PHMSA appreciates the comment and agrees that a one-size-fits-all requirement is not the best approach. Accordingly, PHMSA proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines, that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). Verification of MAOP includes establishing and documenting MAOP if the pipeline segment: (1) Has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs''); (2) Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; or (ii) a class 3 or class 4 location; or (3) the pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before *[effective date of rule]* and is located in one of the following areas: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

In addition, the proposed rule would allow operators to select from among several approaches to verify MAOP based on segment specific issues and limitations, such as pressure testing, pressure reduction based on historical operating pressure, and engineering critical assessment.

Comments submitted for questions in Topic J.

J.1. Should all pipelines that have not been pressure tested at or above 1.1 times MAOP or class location test criteria (§§ 192.505, 192.619 and 192.620), be required to be pressure tested in accordance with the present regulations? If not, should certain types of pipe with a pipeline operating history that has shown to be susceptible to systemic integrity issues be required to be pressure tested in accordance with the present regulations (e.g., low-frequency electric resistance welded (LF–ERW), direct current electric resistance welded (DC–ERW), lap-welded, electric flash welded (EFW), furnace butt welded, submerged arc welded, or other longitudinal seams)? If so, why?

1. AGA, GPTC, and numerous pipeline operators opposed a requirement to pressure test all lines not previously tested. These commenters supported the more-limited testing mandated by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. AGA noted that Congress considered and rejected proposals for more extensive testing.

2. AGA, GPTC, Iowa Utilities Board, Iowa Association of Municipal Utilities, Texas Pipeline Association, Texas Oil & Gas Association, and several distribution pipeline operators objected to requiring pressure testing of distribution pipelines. The commenters argued that the impact of resulting service disruptions was overlooked. Pressure testing would necessitate disruptions of three to seven days for many distribution pipelines, sometimes involving service to an entire town. In some cases, establishing an alternate supply is not always possible. In addition, some in-service lines are not configured in a manner that would support testing. For these reasons, the commenters argued that the high costs to perform pressure tests were inappropriate absent some demonstration of actual risk. MidAmerican added a suggestion that such a requirement of this type be

limited to pipelines operating above 30 percent of specified minimum yield strength (SMYS). Northern Natural Gas agreed with MidAmerican's suggestion and would further limit any testing requirement to pipelines outside of Class 1 locations and subject to seam issues.

3. INGAA, GPTC, Texas Pipeline Association, Texas Oil & Gas Association, and several pipeline operators opposed a blanket testing requirement for older pipelines. The commenters noted that more than sixty percent of in-service pipelines were installed prior to 1970, and have operated safely. INGAA argued that the objective of any action in this area should not be pressure testing, per se, but verification of fitness for service. INGAA noted that all of the listed pipe types are addressed in its Fitness for Service protocol, which would be more effective and efficient than a prescriptive test requirement. A number of additional pipeline operators supported INGAA's comments.

4. Accufacts recommended that all pipelines with at-risk seam anomalies be pressure tested to at least 90% SMYS, with priority given to lines operating under an MAOP established in accordance with 49 CFR 192.619(c).

5. Texas Pipeline Association and Texas Oil & Gas Association noted that pressure testing alone, is not sufficient to prove the integrity of pipelines subject to seam issues. The associations argued that verification must also consider any degradation mechanism present in the seam.

6. Dominion East Ohio supported a requirement to pressure test pipe susceptible to seam failure for which adequate test documentation does not exist.

7. Pipeline Safety Trust, California Public Utilities Commission, Commissioners of Wyoming County Pennsylvania, and an anonymous commenter supported requiring a pressure test for all pipelines not already tested to current requirements. The commenters argued that integrity management should have led to necessary testing but has not done so in all cases. They also noted that such a requirement would respond to an NTSB recommendation.

8. The Environmental Defense Fund (EDF) cautioned that any requirement for pressure testing should assure that the amount of gas blown down to the atmosphere is minimized. It noted that methane is a potent greenhouse gas, and uncontrolled blowdown of 182,000 miles of gas transmission pipeline would be approximately equivalent to the annual greenhouse gas release from 9–14 million autos.

Response to Question J.1 Comments

PHMSA appreciates the information provided by the commenters. This NPRM proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). Verification of MAOP includes establishing and documenting MAOP using one or more of the methods in § 192.624(c)(1) through (c)(6). With regard to the EDF comment regarding the environmental cost due to gas blow down during pressure testing, PHMSA considered this in the rule development. The proposed rulemaking is written to minimize pressure testing. The Integrity Verification Process allows MAOP verification through ILI and ECA. PHMSA believes operators will pressure test as a last resort because it is the costliest methodology. PHMSA estimates that the rule would result in approximately 1,300 miles of pipe being pressure tested. The gas release from controlled low volume release during pressure testing is much less than an uncontrolled high volume release as a result of rupture. The proposed rule is expected to prevent incidents, leaks, and other types of failures that might occur, thereby preventing future releases of greenhouse gases (GHG) to the atmosphere, thus avoiding additional contributions to global climate change. PHMSA estimated net GHG emissions abatement over 15 years of 69,000 to 122,000 metric tons of methane and 14,000 to 22,000 metric tons of carbon dioxide, based on the estimated number of incidents averted and emissions from pressure tests and ILI upgrades.

J.2. Are alternative minimum test pressures (other than those specified in subpart J) appropriate, and why?

1. INGAA, supported by a number of pipeline operators, argued that there is no evidence suggesting that subpart J test pressures are inadequate. INGAA added that there are circumstances in which additional tests to 1.25 times MAOP may be appropriate to verify fitness for service. This is consistent with ASME/ANSI B31.8S and addressed in its Fitness for Service protocol.

2. Texas Pipeline Association, Texas Oil & Gas Association, and Atmos argued that a pressure test at the time of construction is adequate. The associations further added that operating practices since part 192 became effective can also verify fitness for service, if primary test records are not available, particularly if MAOP is reduced.

3. AGA, GPTC, and a number of pipeline operators commented that any test to pressures greater than MAOP has some value. AGA noted that even tests to 1.1 times MAOP would identify the most severe defects that have the potential to adversely affect pipeline integrity.

4. MidAmerican suggested that a fitness for service evaluation should be allowed if there are service interruption issues and for pre-1970 pipelines. MidAmerican would allow testing for existing pipelines, to 1.1 or 1.25 times MAOP or to mill test pressures if they are less than would be required by subpart J.

5. An anonymous commenter argued that alternative minimum test pressures are not appropriate, since they provide no more information than successful operation at normal operating pressures.

6. Accufacts suggested that pipelines tested to lower pressures and that have been subject to aggressive operating cycles be considered for high-pressure testing. Accufacts would also require test pressures be recorded both in psig and percent SMYS.

Response to Question J.2 Comments

PHMSA appreciates the information provided by the commenters. Following publication of the ANPRM, the NTSB issued its report on the San Bruno incident that included a recommendation for this issue (P–11–15). The NTSB recommended that PHMSA amend its regulations so that manufacturing- and construction-related defects can only be considered ''stable'' if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP. This NPRM proposes to revise the integrity management requirement in 192.917(e)(3) to allow the presumption of stable manufacturing and construction defects only if the pipe has been pressure tested to at least 1.25 times MAOP. In addition, PHMSA proposes to revise pressure test safety factors in § 192.619(a)(2)(ii) to correspond to at least 1.25 MAOP for newly installed pipelines.

J.3. Can ILI be used to find seam integrity issues? If so, what ILI technology should be used and what inspection and acceptance criteria should be applied?

1. INGAA and numerous pipeline operators noted that ILI tools can examine seam issues but the technology to identify and evaluate seam anomalies is still evolving. INGAA added that there are significant burdens associated

with requiring pressure testing as an alternative.

2. AGA reported that its discussions with ILI vendors have identified that ILI can detect seam issues but detection is dependent on many conditions and is not guaranteed.

3. Texas Pipeline Association and Texas Oil & Gas Association argued that ILI conducted using a multi-purpose tool can provide a seam assessment equivalent to pressure testing for detection of seam integrity issues, depending on anomaly characteristics and the ILI method used.

4. Northern Natural Gas commented that ILI can be used to detect seam anomalies. Analysis of anomalies is based on the log-secant method with consideration of toughness to determine the predicted failure pressure ratio. The response criteria can then be based on the failure pressure versus maximum allowable operating pressure, similar to wall loss. Northern noted that this is consistent with ASME/ANSI B31.8 and B31.8S.

5. Accufacts commented that ILI cannot, at present, reliably detect all seam anomalies.

Response to Question J.3 Comments

PHMSA appreciates the information provided by the commenters. PHMSA proposes requirements in the rulemaking to address the use of ILI for seam integrity issues. This includes incorporating industry standard NACE SP0102–2010 into the regulations to provide better guidance for conducting integrity assessments with in-line inspection. In addition, for pipe segments subject to MAOP verification in new § 192.624, specific guidance is provided for analyzing crack stability when using engineering critical assessment in conjunction with inline inspection to address seam or other cracking issues.

J.4. Are other technologies available that can consistently be used to reliably find and remediate seam integrity issues?

1. INGAA and numerous pipeline operators noted that magnetic particle inspection is now being used by many operators when pipe with disbanded coating is exposed.

2. GPTC, Northern Natural Gas, and MidAmerican reported that there are other methods that are useful under some circumstances, such as x-ray or other forms of radiography and guided wave ultrasound.

3. Texas Pipeline Association, Texas Oil & Gas Association, and Atmos noted that radiography, ultrasonic testing (UT), and shear wave UT are now being tested.

4. AGA, supported by a number of its pipeline operator members, noted that operators must have the flexibility to select appropriate tools without prior PHMSA approval. AGA argued that technology is advancing rapidly and that PHMSA stifles advancement by requiring prior approval of new inspection tools. AGA argued that some requirements being imposed on the use of other technologies are effectively regulations imposed without formal rulemaking, citing limitations imposed on the use of guided wave ultrasound as an example.

5. Atmos recommended that PHMSA modify its regulations to allow operators to use appropriate methods to evaluate seam integrity without requiring approval as ''other technology.''

6. Accufacts opined that pressure testing and cyclic monitoring and analysis are the only useful technologies currently available.

Response to Question J.4 Comments

PHMSA appreciates the information provided by the commenters. PHMSA proposes requirements in the rulemaking to address the use of best available technology, including use of electromagnetic acoustic transducers (EMAT) or ultrasonic testing (UT) tools to assess seam integrity issues. In addition, proposed requirements include performing fracture mechanics modeling for failure stress pressure and cyclic fatigue crack growth analysis to assess crack or crack-like defects. These requirements would apply to any segment that required verification of MAOP.

J.5. Should additional pressure test requirements be applied to all pipelines, or only pipelines in HCAs, or only pipelines in Class 2, 3, or 4 location areas?

1. INGAA and several pipeline operators argued that existing requirements are adequate and any verification beyond those requirements should rely on INGAA's Fitness for Service protocol. INGAA argued that its protocol is consistent with Section 23 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.

2. MidAmerican suggested any new requirements should focus on pipe with manufacturing and construction defects and should prioritize pipelines in Class 3 and 4 areas and HCAs. MidAmerican sees little benefit in testing other pipelines.

3. An anonymous commenter recommended additional unspecified requirements be applied to pipelines in Class 3 and 4 areas and HCAs.

4. The California Public Utilities Commission would apply pressure testing requirements to HCAs that are determined by the method described in paragraph 1 in the definition of HCA in § 192.903, as a minimum.

5. The Iowa Utilities Board and the Iowa Association of Municipal Utilities argued that class location is not a reasonable basis for determining where to apply pressure testing requirements, given that class location has no relationship to risk. These commenters noted that small-diameter, low-pressure lines could be Class 3, even with no structures intended for human occupancy within a potential impact radius.

6. The Commissioners of Wyoming County Pennsylvania would apply requirements to all transmission and gathering pipelines, including those in Class 1 locations.

7. Thomas Lael noted that all pipelines have been tested once, after construction.

Response to Question J.5 Comments

PHMSA appreciates the information provided by the commenters. This NPRM proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). Use of the MCA location criteria would apply to pipe segments where dwellings, occupied sites, or interstate highways, freeways, and expressways, and other principal 4-lane arterial roadways are located within the potential impact radius, but would not necessarily include all class 3 or 4 locations. Verification of MAOP includes establishing and documenting MAOP using one or more of the methods in 192.624(c)(1) through (c)(6). In addition, this NPRM proposes requirements for verification of pipeline material in new § 192.607 for existing onshore, steel, gas transmission pipelines that are located in an HCA or class 3 or class 4 locations.

J.6. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*

- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

K. Establishing Requirements Applicable to Underground Gas Storage

Underground storage facilities are comprised of wells and associated separation, compression, and metering facilities to inject and withdraw natural gas at high pressures from depleted hydrocarbon reservoirs and salt caverns. Pipelines that transport gas within a storage field are defined in § 192.3 as transmission pipelines and are regulated by PHMSA, while underground storage facilities including surface and subsurface well casing, tubing, and valves are not currently regulated under part 192. In the ANPRM, PHMSA provided a brief history of a 1992 accident that occurred in Brenham, Texas an involving underground storage facility. This incident involved an uncontrolled release of highly volatile liquids from a salt dome storage cavern that resulted in 3 fatalities, 21 people treated for injuries at area hospitals, and damages in excess of $9 million. Following the incident, the National Transportation Safety Board (NTSB) conducted an investigation that resulted in a recommendation for the Research and Special Programs Administration, the precursor to PHMSA, to initiate a rulemaking proceeding. Following a period of study, RSPA terminated that rulemaking. RSPA described this action in an Advisory Bulletin published in the **Federal Register** on July 10, 1997 (ADB–97–04, 62 FR 37118).

Since publication of the 1997 Advisory Bulletin, significant incidents have continued to occur involving underground gas storage facilities. The most significant incident occurred in 2001 near Hutchinson, Kansas. An uncontrolled release from an underground gas storage facility resulted in an explosion and fire, in which two people were killed. Many residents were evacuated from their homes and were not able to return for four months.

The Kansas Corporation Commission initiated enforcement action against the operator of the Hutchinson storage field as a result of safety violations associated with the accident. As part of this enforcement proceeding, it was concluded that the storage field was an interstate gas pipeline facility. Federal statutes provide that ''[a] State authority may not adopt or continue in force safety standards for interstate pipeline facilities or interstate pipeline transportation'' (49 U.S.C. 60104). There were, and remain, no federal safety standards against which enforcement could be taken. Therefore, the enforcement proceeding was terminated.

The ANPRM listed questions for consideration and comment. The following are general comments received related to this topic as well as comments related to the specific questions:

General Comments for Topic K

1. AGA, supported by a number of pipeline operators, suggested that any proceeding addressing gas storage be conducted under a docket separate from any pipeline requirements, arguing that the relevant engineering and regulatory concepts are vastly different.

2. The Kansas Department of Health and Environment (KDHE) noted that the ANPRM misstated the agency that took enforcement action in the case of the Kansas gas storage incident previously discussed. That action was taken by KDHE, and not the Kansas Corporation Commission, as stated.

3. Kansas Corporation Commission recommended that PHMSA work with the states to have Congress amend the Pipeline Safety Act to allow the states to regulate interstate and intrastate gas storage wellbores. KCC noted that current federal regulations undermine the ability of states to regulate gas storage facilities, as in the 2001 accident where Kansas attempted to take enforcement as a result of a serious incident but was precluded from doing so by pre-emption of federal regulations.

4. The Interstate Oil & Gas Compact Commission argued that states should be mandated to regulate gas storage wellbores, whether interstate or intrastate.

5. The Texas Pipeline Association and Texas Oil & Gas Association opposed new requirements, arguing that there has been no demonstration of undue risk or insufficiency of current regulations.

Comments submitted for questions in Topic K.

K.1. Should PHMSA develop Federal standards governing the safety of underground gas storage facilities? If so, should they be voluntary? If so, what portions of the facilities should be addressed in these standards?

1. INGAA suggested that PHMSA develop high-level, performance-based guidelines that acknowledge and reflect existing applicable state rules to address regional and geologic variations in underground storage activity. Development of guidelines should follow PHMSA's current practice of stakeholder involvement leading to development of a consensus standard and its subsequent adoption into regulations. INGAA reported that it is committed to developing a standard under the auspices of the American Petroleum Institute (API), with work beginning in 2012. INGAA cautioned that it is important to understand, and clearly state, the scope of ''gas storage,'' which it contends begins at and includes the wing valve at the wellhead, the wellhead components, the well bore, and the ''underground container'' (*i.e.,* the geologic formation). INGAA stated that PHMSA should recognize the limits and requirements imposed on gas storage by FERC, arguing that no new regulations are needed in these areas. A number of pipeline operators supported INGAA's comments, and have submitted separate comments addressing one or more of these points.

2. AGA suggested that PHMSA adopt federal performance standards, in conjunction with API. AGA argued that one-size-fits-all requirements are not appropriate in this area, since they would fail to recognize variations in wells and the geologic diversity of storage caverns and structures. AGA argued that no new requirements are needed governing maximum operating parameters and environmental conditions, since these are addressed adequately by existing federal and state certification and compliance programs related to gas storage facilities. AGA recommended that any new standards should be mandatory, but also recognize regional variations by state due to geologic and geographical diversity among storage fields. A number of pipeline operators supported AGA's comments.

3. INGAA, the Kansas Corporation Commission, and the Interstate Oil & Gas Compact Commission recommended that compliance with any new standards be mandatory, but that regulatory authority should be delegated to the states since PHMSA lacks relevant technical expertise. A number of pipeline operators supported this comment.

4. The Kansas Corporation Commission and the Interstate Oil & Gas Compact Commission recommended that any new standards cover all portions of a storage facility and that PHMSA enter into a memorandum of understanding with FERC regarding gas containment.

5. Southern Star Central Gas Pipeline agreed that the development of requirements for operation of gas storage facilities is appropriate but explicitly disagreed with Kansas Corporation Commission's suggestion that development be delegated to states.

Southern Star indicated that it would not object to the delegation of inspection and enforcement to federal standards. Southern Star noted that a federal court has held only federal regulations can be enforced against its storage facilities. The company also argued that no new requirements are needed for storage reservoirs given existing FERC regulations.

6. GPTC, Nicor, Ameren Illinois, and Atmos argued that existing regulations are sufficient and that no new standards are needed. GPTC and Nicor added that if PHMSA elects to develop new requirements, they should be limited to facilities ''affecting interstate or foreign commerce.'' Atmos added that geology and circumstances vary considerably among gas storage facilities and states have the requisite expertise to regulate storage safety.

7. Texas Pipeline Association and Texas Oil & Gas Association argued that PHMSA lacks the expertise to regulate wellbores and therefore should not attempt to develop gas storage regulations.

8. FERC, NAPSR, Interstate Oil & Gas Compact Commission, Iowa Utilities Board, Kansas Corporation Commission, and Railroad Commission of Texas recommended that PHMSA seek statutory authority to confer jurisdiction over all gas storage facilities to the states. The commenters argued that states have expertise on local geology and storage fields and could therefore regulate in a fashion similar to that of production facilities. The commenters referred to PHMSA's Advisory Bulletin ADB 97–04 as a further basis for this recommendation. FERC further suggested that PHMSA delegate inspection and enforcement activities to states if statutory changes are not forthcoming.

9. The Alaska Department of Natural Resources recommended that PHMSA develop standards in consultation with the states.

10. The NTSB encouraged the development of gas storage regulations, noting that this was the subject of its recommendation P–93–9, which it closed as ''unacceptable action,'' after a rulemaking proceeding to regulate underground gas storage was terminated in 1997.

11. A private citizen suggested that there should be some level of regulation, as gas storage is currently insufficiently regulated.

12. NAPSR commented that, in many states, the agency familiar with gas storage issues is not responsible for regulation of pipeline safety. As a result, NAPSR stated that certification of additional state agencies may be required.

13. An anonymous commenter suggested that PHMSA should develop requirements applicable to piping within gas storage facilities. The commenter argued that caverns, well heads, casing, tubing, fresh water, and brine pumping are generally regulated by states.

14. ITT Exelis Geospatial Systems suggested that PHMSA consider requirements for leak detection, noting that their LIDAR system could serve this purpose.

K.2. What current standards exist governing safety of these facilities? What standards are presently used for conducting casing, tubing, isolation packer, and wellbore communication and wellhead equipment integrity tests for down-hole inspection intervals? What are the repair and abandonment standards for casings, tubing, and wellhead equipment when communication is found or integrity is compromised?

1. AGA, INGAA, GPTC, Texas Pipeline Association, Texas Oil & Gas Association and numerous pipeline operators noted that FERC, EPA, and the states regulate various aspects of gas storage. Commenters reported that state regulations generally provide standards for wells and that EPA regulations provide standards for caverns. AGA described the aspects regulated by FERC, EPA, and the states and suggested provisions of each which might be considered for new PHMSA regulations. For example, it was recommended that a federal guideline be established to require a storage operator notification-review-and-approval process for third party wells encroaching on storage containers, which is a requirement some states currently have in place. Commenters reported that repaired wells must meet state standards for new wells and state requirements for abandonment vary. AGA indicated that interstate storage operators use state requirements as guidance in the absence of federal regulations.

2. The Kansas Department of Health and Environment, the Kansas Corporation Commission, the Railroad Commission of Texas, the Interstate Oil & Gas Compact Association, Ameren Illinois, and Atmos reported that states generally regulate gas storage. For example, in Texas, Statewide Rule 16 applies and KDHE submitted a copy of its gas storage regulations.

3. Texas Pipeline Association and Texas Oil & Gas Association noted that Texas requirements for gas storage are more similar to provisions that would govern production drilling and operations rather than pipeline operations.

K.3. What standards are used to monitor external and internal corrosion?

1. AGA, INGAA, and numerous pipeline operators noted that varying approaches are used and argued that prescriptive standards would be inappropriate given that no one tool is applicable to all wells and well casings are not available for direct examination.

2. The Railroad Commission of Texas reported that its regulations require integrity testing every five years or after a well work over. Texas regulations also require periodic casing inspections and a pipeline integrity program.

3. Northern Natural Gas reported that it uses the same measures to monitor corrosion in its gas storage facilities as it does for its pipelines.

K.4. What standards are used for welding, pressure testing, and design safety factors of casing and tubing including cementing and casing and casing cement integrity tests?

1. INGAA, AGA, the Texas Pipeline Association, the Texas Oil & Gas Association and numerous pipeline operators noted that state requirements reflect unique situations, welding is seldom used, pressure capacity is demonstrated by historical record, and casing requirements are customized for local geologic conditions. Welding, when used, is generally performed to procedures compliant with ASTM B31.8, part 192, and inspection is conducted to API–1104 criteria.

2. The Railroad Commission of Texas reported that Texas regulations are flexible to allow for site-specific decisions.

K.5. Should wellhead valves have emergency shutdowns both primary and secondary? Should there be integrity and O&M intervals for key safety and CP systems?

1. INGAA, AGA, and several pipeline operators reported that storage in salt domes generally requires emergency shutdown systems; these systems are generally not required for storage in depleted gas fields or aquifers but may be required depending on local site conditions. The commenters indicated that testing intervals are set in accordance with operator procedures and CP testing is based on an operator's local experience.

2. The Railroad Commission of Texas, the Texas Pipeline Association, and the Texas Oil & Gas Association reported that Texas' regulations require emergency shutdown systems and annual drills.

3. The Kansas Department of Health and Environment suggested that at least

the primary well should have an emergency shutdown system. KDHE stated that O&M intervals should be established for key safety systems and attached a copy of the relevant Kansas regulations to its comments.

4. Northern Natural Gas suggested that emergency shutoffs should only be required when the well is within 330 feet of a structure intended for human occupancy. Northern stated that intervals should be established for O&M activities and CP systems.

5. GPTC and Nicor expressed their opinion that no new regulations are needed in this area; decisions on emergency shutdown should be made based on local circumstances.

K.6. What standards are used for emergency shutdowns, emergency shutdown stations, gas monitors, local emergency response communications, public communications, and O&M Procedures?

1. AGA, GPTC, and several pipeline operators reported that operators generally follow DOT regulations, where applicable, and industry good practices.

2. The NTSB commented that gas storage facility information should be made available to emergency responders, per its recommendation P–11–8.

3. The Railroad Commission of Texas, the Texas Pipeline Association, the Texas Oil & Gas Association, and Atmos reported that states establish standards in these areas through their regulations.

4. The Kansas Department of Health and Environment reported that these standards are specified in its regulations, and submitted a copy of its regulations as an attachment to its comments.

K.7. Does the current lack of Federal standards and preemption provisions in Federal law preclude effective regulation of underground storage facilities by States?

1. INGAA, supported by several of its member companies, noted that jurisdiction over gas storage facilities in interstate pipeline systems is federal.

2. AGA and several of its pipeline operator members suggested that federal standards could assure a degree of consistency, and uniform standards would promote integrity and safety. AGA opined that implementation of federal standards could be delegated to the states.

3. GPTC and Nicor opined that federal regulations are not needed; as states are not now precluded from regulating gas storage and many do so.

4. The Texas Pipeline Association, the Texas Oil & Gas Association, Atmos, Ameren Illinois, and Northern Natural Gas opined that effective state regulation is not now precluded. The commenters stated that state regulation in combination with applicable FERC and DOT requirements has been demonstrated to assure safety successfully.

5. The Kansas Department of Health and Environment and the Kansas Corporation Commission noted that state regulation of the safety of interstate gas storage facilities is currently precluded. When Kansas attempted to enforce its requirements following an accident at an interstate storage facility, it was prevented from doing so by a federal court on the basis of federal preemption. The agencies noted that lack of action by PHMSA or FERC on interstate gas storage facility safety precludes states from taking any action and leaves these facilities essentially unregulated.

K.8. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

Response to All Topic K Comments

Since the publication of the ANPRM and the close of its comment period, Southern California Gas Company's (SoCal Gas) Aliso Canyon Natural Gas Storage Facility Well SS25 failed, causing a sustained and uncontrolled natural gas leak near Los Angeles, California. The failure, possibly from the downhole well casing, resulted in the relocation of more than 4,400 families according to the Aliso Canyon Incident Command briefing report issued on February 1, 2016. On January 6, 2016, California Governor Jerry Brown issued a proclamation declaring the Aliso Canyon incident a state emergency. On February 5, 2016, PHMSA issued an advisory bulletin in the **Federal Register** (81 FR 6334) to remind all owners and operators of underground storage facilities used for the storage of natural gas to consider the overall integrity of the facilities to ensure the safety of the public and operating personnel and to protect the environment. The advisory bulletin specifically reminded these operators to review their operations and identify the potential of facility leaks and failures, review the operation of their shut-off and isolation systems, and maintain updated emergency plans. In addition, PHMSA used the advisory bulletin to advocate the review of a previous advisory bulletin (97–04) dated July 10, 1997 and the voluntary implementation of American Petroleum Institute (API) 1170 ''Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage, First Edition, July 2015,'' API RP 1171 ''Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, First Edition, September 2015,'' and Interstate Oil and Gas Compact Commission (IOGCC) standards entitled ''Natural Gas Storage in Salt Caverns—A Guide for State Regulators'' (IOGCC Guide), as applicable. PHMSA will consider proposing a separate rulemaking to address the safety of underground natural gas storage facilities. Proposing a separate rulemaking that specifically focuses on improving the safety of underground natural gas storage facilities will allow PHMSA to fully consider the impacts of incidents that have occurred since the close of the initial comment period. It will also allow the Agency to consider voluntary consensus standards that were developed after the close of the comment period for this ANPRM, and to solicit feedback from additional stakeholders and members of the public to inform the development of potential regulations.

L. Management of Change

The ANPRM requested comments regarding the addition of requirements for the management of change to provide a greater degree of control over this element of pipeline risk, particularly following changes to physical configuration or operational practices. Operation of a pipeline over an extended period without effective management of change, such as changes to pipeline systems (*e.g.,* pipeline equipment, computer equipment or software used to monitor and control the pipeline) or to practices used to construct, operate, and maintain those systems, can result in safety issues. Changes can introduce unintended consequences if the change is not well thought out or is implemented in a manner not consistent with its design or planning. Similarly, changes in procedures require people to perform new or different actions, and failure to train them properly and in a timely

manner can result in unexpected consequences. The result can be a situation in which risk or the likelihood of an accident is increased. A recently completed but poorly-designed modification to the pipeline system was a factor contributing to the Olympic Pipeline accident in Bellingham, Washington. The following are general comments received related to this topic as well as comments related to the specific questions:

General Comments for Topic L

1. INGAA and several of its pipeline operator members disagreed with the implication in the ANPRM that change management is not now addressed in regulations. They pointed out that § 192.911(k) and ASME/ANSI B31.8S (incorporated by reference) already address this subject. INGAA reported that its members are committed to clarifying and expanding the use of a formal ''management of change'' process, and to facilitating its consistent application as a key management system. INGAA expressed its belief that the full adoption of ASME/ANSI B31.8S will facilitate the widespread application of these principles. Dominion East Ohio Gas also noted that part 192 already contains a management of change process. In addition, Chevron noted that management of change programs are generally specific to the organizational, operational, and ownership structures of the company, and part 192 already addresses this subject.

2. A private citizen opined that management of change is necessarily an integral part of quality management systems and another private citizen supported management of change requirements, noting that accidents often result from changes to systems. The Alaska Department of Natural Resources also supported PHMSA's goal of establishing management of change requirements or guidelines.

Response to General Comments for Topic L

PHMSA appreciates the information provided by the commenters. PHMSA agrees management of change is currently addressed in § 192.911(k). However, because of its importance, and consistent with INGAA members' commitment to expanding use of formal MOC processes, PHMSA believes it is prudent to provide greater emphasis on MOC directly within the rule text.

Therefore, PHMSA proposes to clarify integrity management requirements for management of change by explicitly including aspects of an effective management of change process into the rule text to emphasize the current requirements. In addition, PHMSA also proposes to add a new subsection 192.13(d) that would apply to onshore gas transmission pipelines, and require that an evaluation must be performed to evaluate and mitigate, as necessary, the risk to the public and environment as an integral part of managing pipeline design, construction, operation, maintenance and integrity, including management of change. The new paragraph would also articulate the general requirements for a management of change process, consistent with Section 192.911(k).

Comments submitted for questions in Topic L.

L.1. Are there standards used by the pipeline industry to guide management processes including management of change? Do standards governing the management of change process include requirements for IM procedures, O&M manuals, facility drawings, emergency response plans and procedures, and documents required to be maintained for the life of the pipeline?

1. AGA, supported by several of its members, and several transmission pipeline operators questioned why this question was in the ANPRM, noting that management of change requirements are already promulgated in § 192.911(k). GPTC added that § 192.909 also addresses this subject.

2. INGAA reported that Section 11 of ASME/ANSI B31.8S is the industry standard in this area, and all of the considerations in this question are included in operators' management of change processes. Several pipeline operators supported this comment.

3. Atmos reported that it is not aware of any standards used by the industry to guide management of change processes. Atmos does not have a formal management of change process, except in its integrity management program, but expressed its conclusion that existing practices within the company contribute to its ability to manage change.

4. Texas Pipeline Association (TPA) reported that its members do not have formal management of change processes but comply with regulations that address proxy requirements (*e.g.,* § 192.911). TPA expressed its belief that part 192, taken as a whole, includes management of change requirements to which its members adhere. Texas Oil & Gas Association supported TPA's comments.

5. California Public Utilities Commission reported that it is unaware of any pipeline industry standards in this area.

6. An anonymous commenter opined that most operators do not have management of change processes.

7. The NTSB recommended that PHMSA require operators of natural gas transmission and distribution pipelines and hazardous liquid pipelines to ensure that their control room operators immediately notify the relevant 911 emergency call centers of possible ruptures (Recommendation P–11–9).

8. TransCanada reported that it is committed to clarifying and expanding the use of a formal ''management of change'' process. TransCanada expressed its conclusion that the full adoption of ASME/ANSI B31.8S will facilitate the widespread application of management of change principles.

Response to Question L.1 Comments

PHMSA appreciates the information provided by the commenters, which did not identify any standards beyond ASME/ANSI B31.8S, which is already invoked by part 192, and used by the pipeline industry to guide management processes including management of change. See response to the general comments for Topic L, above.

L.2. Are standards used in other industries (e.g., Occupational Safety and Health Administration standards at 29 CFR 1910.119) appropriate for use in the pipeline industry?

1. INGAA reported that Section 11 of ASME/ANSI B31.8S is based on OSHA's Process Safety Management (PSM) standards. INGAA noted that OSHA worked with industry in developing PSM standards that would identify potential threats and assure that mitigative actions were taken. Several pipeline operators supported INGAA's comments.

2. AGA and GPTC expressed their belief that there is no benefit in comparing standards with other industries, reiterating that §§ 192.909 and 192.911 and ASME/ANSI B31.8S already include management of change. Several pipeline operators supported AGA's comments.

3. The Texas Pipeline Association and the Texas Oil & Gas Association reported that their members are aware of standards used in other industries but do not believe they are appropriate or applicable to the pipeline industry.

4. The Iowa Association of Municipal Utilities expressed its conclusion that OSHA standards are complicated and would be unduly costly for small municipal utilities.

5. Accufacts noted that transportation pipelines are specifically excluded from OSHA regulation; however, this does not prevent PHMSA from incorporating elements of 29 CFR 1910.119 into the

federal pipeline safety regulations in order to mandate a more prudent pipeline safety culture.

6. Atmos reported that it has no experience with standards used in other industries but noted that OSHA standards appear to be directed toward situations where processes interact such that a change in one process affects a second or third process.

7. Ameren Illinois suggested that standards from other industries would need to be studied to determine if they are applicable to the pipeline industry.

8. An anonymous commenter suggested that the OSHA standards are a good model for pipelines, as they are well written and thought out.

Response to Question L.2 Comments

PHMSA appreciates the information provided by the commenters. See response to the general comments for Topic L, above.

L.3. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

M. Quality Management Systems (QMS)

The ANPRM requested comments on whether and how to impose requirements related to quality management systems. Quality management includes the activities and processes that an organization uses to achieve quality. These include formulating policy, setting objectives, planning, quality control, quality assurance, performance monitoring, and quality improvement.

Achieving quality is critical to gas transmission pipeline design, construction, and operations. PHMSA recognizes that pipeline operators strive to achieve quality, but our experience has shown varying degrees of success in accomplishing this objective among pipeline operators. PHMSA believes that an ordered and structured approach to quality management can help pipeline operators achieve a more consistent state of quality and thus improve pipeline safety.

PHMSA's pipeline safety regulations do not currently address process management issues such as quality management systems. Section 192.328 requires a quality assurance plan for the construction of pipelines intended to operate at an alternative MAOP, but there is no similar requirement applicable to other pipelines. Quality assurance is generally considered to be an element of quality management. Important elements of quality management systems are their design and application to control (1) the equipment and materials used in new construction (*e.g.,* quality verification of materials used in construction and replacement, post-installation quality verification), and (2) the contractor work product used to construct, operate, and maintain the pipeline system (*e.g.,* contractor qualifications, verification of the quality of contractor work products).

The ANPRM then listed questions for consideration and comment. The following are general comments received related to this topic as well as comments related to the specific questions:

General Comments for Topic M

1. MidAmerican suggested that PHMSA work with the committees for ASME/ANSI B31.8 and B31.8S to address these topics more fully, if PHMSA believes more is needed. MidAmerican opined that a general rule addressing quality management systems would divert resources and adversely affect safety, if applied to this already heavily-regulated industry.

2. The Alaska Department of Natural Resources supported quality management systems and suggested that pipeline operators should apply such standards to their contractors.

3. A private citizen supported quality management systems, noting that this is an area that would be difficult to regulate but might be an element in incentive programs.

Comments submitted for questions in Topic M.

M.1. What standards and practices are used within the pipeline industry to assure quality? Do gas transmission pipeline operators have formal QMS?

1. INGAA opined that achieving consistent quality materials, construction and management is an appropriate focus for the INGAA Foundation, which has sponsored and will continue to sponsor workshops on this subject. INGAA reported that the Foundation plans to publish five relevant White Papers in 2012 and its Integrity Management—Continuous Improvement team is currently working on guidelines. INGAA also noted that there are elements of a quality management system in ASME/ANSI B31.8S, already incorporated by reference, including quality assurance/quality control, management of change, communication and performance measurement, Standards, specifications, and procedures governing pipe and appurtenances form part of a pipeline quality management system. INGAA cited ISO (9001:2008/29001:2010) and API (Spec Q1) quality management standards as references that are available for operator use. INGAA further noted that API published Spec Q2 in December 2011. Several pipeline operators supported INGAA's comments.

2. AGA, GPTC, Nicor, Atmos, the Texas Pipeline Association, and the Texas Oil & Gas Association suggested that part 192, taken as a whole, is essentially a quality management system. AGA provided a summary listing of part 192 requirements that assure quality. A number of additional pipeline operators supported AGA's comments.

3. Ameren Illinois reported that it has a quality assurance program for pipeline construction that includes building alliances with excavators and other elements.

4. Paiute and Southwest Gas reported that their practices beyond compliance with part 192 requirements include operator qualification (OQ) for construction, an internal quality assurance group, root cause analysis of events, and quality control verification of OQ.

5. MidAmerican reported that it has no formal quality management system but applies standards to assure quality processes. In particular, ASME/ANSI B31.8 and B31.8S and ANSI/ISO/ASQ Q9004–2000 were used to guide its company quality programs. MidAmerican also has a contractor oversight program.

6. An anonymous commenter opined that most operators have a quality management system, often incorporated into their SCADA system, to satisfy customers or end user requirements. The commenter suggested that some of these systems have only recently been modified to address internal corrosion mechanisms, often identified as part of operators' integrity management programs.

M.2. Should PHMSA establish requirements for QMS? If so, why? If so, should these requirements apply to all gas transmission pipelines and to the complete life cycle of a pipeline system?

1. INGAA, supported by a number of its pipeline operator members, asserted that no new requirements are appropriate at this time. INGAA noted that much work is ongoing in this area and it may be appropriate to adopt some standards (*e.g.,* API Q1 or Q2) in the future.

2. AGA, GPTC, the Texas Pipeline Association, the Texas Oil & Gas Association, Oleksa and Associates, and numerous pipeline operators expressed an opinion that new quality assurance requirements are not needed. These commenters view part 192 as quality assurance requirements and argue that a new programmatic requirement would not be beneficial.

3. TransCanada opined that quality management systems need to be adopted throughout the entire industry and embraced by operators and contractors alike, arguing that this would provide a more consistent level of quality throughout the industry. TransCanada opined that the INGAA Foundation is the appropriate venue in which to develop guidelines.

4. Northern Natural Gas opined that the existing process, which includes PHMSA/State inspections, is adequate.

5. A private citizen commented that quality management systems should be required to improve pipeline safety, including documentation, investigations, validation, audits/inspections, change management, training, and quality/management oversight.

6. An anonymous commenter opined that no new requirements are needed, arguing that most operators have such systems.

M.3. Do gas transmission pipeline operators require their construction contractors to maintain and use formal QMS? Are contractor personnel that construct new or replacement pipelines and related facilities already required to read and understand the specifications and to participate in skills training prior to performing the work?

1. INGAA reported that most of its members apply quality management principles, including requiring contractors conform to specified requirements, though the approach varies from operator to operator. INGAA acknowledged, however, that ''[t]here is room to establish a more structured approach to QMS for operators and construction contractors'' to assure more consistency. A number of pipeline operators supported INGAA's comments.

2. AGA reported that transmission operators have the means to assure contractor work quality and that most LDC operators impose operator qualification (OQ) and other specific requirements on their construction contractors.

3. The Texas Pipeline Association and the Texas Oil & Gas Association encouraged PHMSA not to adopt requirements for operators to train construction personnel. The associations expressed concerns over potential liability and their preference for a performance-based standard.

4. Ameren Illinois, Atmos, and MidAmerican reported that they apply operator qualification (OQ) requirements on their contractors.

5. Northern Natural Gas, Paiute, and Southwest Gas reported that they do not require contractors to have formal QMS but do require conformance to various standards.

6. Oleksa and Associates reported its experience that operators require construction contractors to meet the same standards as their employees.

7. GPTC, Nicor, and an anonymous commenter suggested that compliance with construction regulations contribute to QMS through requirements for specifications and inspections.

8. NAPSR, the Texas Pipeline Association, and the Texas Oil & Gas Association suggested that operator qualification (OQ) requirements be applied to construction, since this would apply formal QMS to the full range of construction and operation.

M.4. Are there any standards that exist that PHMSA could adopt or from which PHMSA could adapt concepts for QMS?

1. INGAA and a number of pipeline operators suggested that several standards could be used as general references, including ISO 9001:2008 (Quality Management Systems), ISO 29001:2010 (Oil and Gas) and API Spec Q1 (Oil and Gas). INGAA opined that compliance with these standards should not be required, and added that additional standards, white papers, and guidance are under development.

2. The AGA, GPTC, Nicor, and Ameren Illinois opposed new requirements in this area. AGA opined that part 192 is already ''saturated'' with this type of requirement. A number of additional pipeline operators supported AGA's comments.

3. The NTSB recommended improvement to PHMSA's drug and alcohol requirements, citing their recommendations P–11–12 & 13.

4. A private citizen suggested that, by extrapolating from the practices of a pipeline operator with a good safety record. The commenter stated that useful references include the Baldrige Performance Excellence Program and Quality Management Standard ISO 9000.

M.5. What has been the impact on cost and safety in other industries in which requirements for a QMS have been mandated?

1. INGAA reported that quality management systems have been demonstrated to reduce risk and opined that the keys to a successful QMS are simplicity, empowerment, accountability and ease of implementation. A number of pipeline operators supported INGAA's comments.

M.6. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

• *The potential costs of modifying the existing regulatory requirements.*

• *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*

• *The potential impacts on small businesses of modifying the existing regulatory requirements.*

• *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

Response to All Topic M Comments

PHMSA appreciates the information provided by the commenters. PHMSA does not propose additional rulemaking for this topic at this time. PHMSA will review the comments received on the ANPRM and will consider them in future rulemaking.

N. Exemption of Facilities Installed Prior to the Regulations

The ANPRM requested comments regarding proposed changes to part 192 regulations that would eliminate provisions that exempt pipelines from pressure test requirements to establish MAOP. Federal pipeline safety regulations were first established with the initial publication of part 192 on August 19, 1970 (35 FR 13248). Gas transmission pipelines had existed for many years prior to this, some dating to as early as 1920. Many of these older pipelines had operated safely for years at pressures higher than would have been allowed under the new regulations. It was concluded that a required reduction in the operating pressure of these pipelines would not have resulted in a material increase in safety. Therefore, a provision was included in the regulations (§ 192.619(c)) that allowed pipelines to

operate at the highest actual operating pressure to which they were subjected during the 5 years prior to July 1, 1970. The safe operation of these pipelines at these pressures was deemed to be evidence that operation could safely continue.

Many gas transmission pipelines continue to operate in the United States under an MAOP established in accordance with § 192.619(c). Some of these pipelines operate at stress levels higher than 72 percent specified minimum yield strength (SMYS), the highest level generally allowed for more modern gas transmission pipelines. Some pipelines operate at greater than 80 percent SMYS, the alternate MAOP allowed for some pipelines by regulations adopted October 17, 2008 (72 FR 62148). Under these regulations, operators who seek to operate their pipelines at up to 80 percent SMYS (in Class 1 locations) voluntarily accept significant additional requirements applicable to design, construction, and operation of their pipeline that are intended to assure quality and safety at these higher operating stresses. Pipelines that operate under an MAOP established in accordance with § 192.619(c) are subject to none of these additional requirements.

Part 192 also includes several provisions other than establishment of MAOP for which an accommodation was made in the initial part 192. These provisions allowed pipeline operators to use steel pipe that had been manufactured before 1970 and did not meet all requirements applicable to pipe manufactured after part 192 became effective (192.55); valves, fittings and components that did not contain all the markings required (192.63); and pipe which had not been transported under the standard included in the new part 192 (192.65, subject to additional testing requirements).

The ANPRM then listed questions for consideration and comment. The following are general comments received related to this topic as well as comments related to the specific questions:

General Comments for Topic N

1. INGAA and a number of pipeline operators opined that age alone is not an appropriate criterion for determining a pipeline's fitness for service. Old pipe that is well maintained operates safely and unfit pipe should be replaced regardless of age. INGAA suggested that fitness for service of pipe in HCAs should be evaluated using available records, if adequate, or through new testing. INGAA attached a white paper to its comments that described its Fitness for Service protocol. INGAA also cautioned that any requirement to reconfirm MAOP should be subject to a rigorous cost-benefit analysis, as hydrostatic testing is very expensive and could require outages of up to several weeks.

2. A private citizen suggested phasing out sub-standard or systems that pre-date regulatory requirements where public safety is concerned, implying that this has been done in other areas (citing elimination of radium dial watches and leaking underground storage tanks as examples).

3. A private citizen suggested that legacy facilities should be subject to a timetable to come into full compliance with current regulations, arguing that this would improve safety and knowledge of older facilities.

Response to General Comments for Topic N

PHMSA appreciates the information provided by the commenters. NTSB recommended that regulatory exemptions be repealed. In addition, section 23 of the Act addressed gas transmission pipelines without records sufficient to validate MAOP. In response to these concerns, this NPRM proposes requirements for verification of maximum allowable operating pressure (MAOP) in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). Verification of MAOP includes establishing and documenting MAOP if the pipeline MAOP was established in accordance with § 192.619(c), the grandfather clause. In addition, this NPRM proposes requirements for verification of pipeline material in accordance with new § 192.607 for existing onshore, steel, gas transmission pipelines that are located in an HCA or class 3 or class 4 locations.

Comments Submitted for Questions in Topic N

N.1. Should PHMSA repeal provisions in part 192 that allow use of materials manufactured prior to 1970 and that do not otherwise meet all requirements in part 192?

1. INGAA, supported by several pipeline operators, suggested age, alone, should not be a criterion for determining fitness for service, noting some pre-regulation materials (*e.g.*, seamless pipe) are as good as today's.

2. AGA, GPTC, and numerous pipeline operators noted it is illogical to storehouse pre-1970 materials for installation now. AGA indicated that it thus did not understand the purpose of the ANPRM question.

3. Iowa Utilities Board, NAPSR, Texas Pipeline Association, Texas Oil & Gas Association, Accufacts, Alaska Department of Natural Resources, Atmos, Commissioners of Wyoming County Pennsylvania, Professional Engineers in California Government, and an anonymous commenter encouraged repeal of this allowance. Some of these commenters would allow a specified time period for operators to come into compliance.

4. Thomas Lael and MidAmerican recommended operators be allowed to continue use of materials that have already been placed into service, arguing that they have been demonstrated safe through integrity management.

5. Ameren Illinois and Northern Natural Gas opposed repeal of this provision.

Response to Question N.1 Comments

PHMSA appreciates the information provided by the commenters. As stated above, this NPRM proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). In addition, this NPRM proposes requirements for verification of pipeline material in accordance with new § 192.607 for existing onshore, steel, gas transmission pipelines that are located in an HCA or class 3 or class 4 locations.

N.2. Should PHMSA repeal the MAOP exemption for pre-1970 pipelines? Should pre-1970 pipelines that operate above 72% SMYS be allowed to continue to be operated at these levels without increased safety evaluations such as periodic pressure tests, in-line inspections, coating examination, CP surveys, and expanded requirements on interference currents and depth of cover maintenance?

1. INGAA and a number of pipeline operators opposed repeal of this exemption. INGAA suggested its Fitness for Service protocol be used to assure continued safety of old pipe.

2. AGA, GPTC, Texas Pipeline Association, Texas Oil & Gas Association and numerous pipeline operators commented that the wording of this question creates a false impression. There is no exemption for MAOP. Rather, the regulations establish requirements for determining MAOP and the only ''exemption'' is to a post-construction hydrostatic test, since the pipeline was in service at the time the regulations became effective.

3. AGA, supported by several of its pipeline operator members, contended the appropriate method for verifying

MAOP of older pipelines is for PHMSA to follow Section 23 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. AGA opposed eliminating § 192.619(c) for determining MAOP of older pipelines, arguing that it would cripple the nation's gas pipeline capacity. A number of additional pipeline operators joined AGA in opposing any new requirement to pressure test all older pipelines, arguing costs would be excessive and there would be significant potential to interrupt gas services. AGA included a white paper with its comments outlining its suggested approach to MAOP verification.

4. Accufacts, Texas Pipeline Association, and Texas Oil & Gas Association opposed requiring all pre-1970 pipelines to reduce MAOP, if necessary, to a pressure that would impose stresses no greater than 72 percent SMYS. Accufacts noted this pipe is still safe at its current operating pressure if it is managed properly, but suggested a possible focus on interactive threats that might make seam welds unstable.

5. Ameren Illinois opposed modifying MAOP requirements for pre-1970 pipelines.

6. NAPSR, the NTSB, and Professional Engineers in California Government supported repeal of exemptions applying to MAOP of pre-1970 pipelines. NAPSR added PHMSA should not allow any pipeline to operate at pressures above that which would impose stresses greater than 72 percent SMYS.

7. MidAmerican suggested use of a performance-based approach, which might include a fitness for service determination for pipe in Class 2, 3, or 4 areas or HCA.

8. Commissioners of Wyoming County Pennsylvania would support repeal of MAOP exemptions because pipeline infrastructure is aging and they see additional safety measures needed.

Response to Question N.2 Comments

PHMSA appreciates the information provided by the commenters. As stated above, this NPRM proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). Verification of MAOP includes establishing and documenting MAOP if the pipeline segment: (1) Has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs''); (2) Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; or (ii) a class 3 or class 4 location; or (3) the pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before *[effective date of rule]* and is located in one of the following areas:

(i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

N.3. Should PHMSA take any other actions with respect to exempt pipelines? Should pipelines that have not been pressure tested in accordance with subpart J be required to be pressure tested in accordance with present regulations?

1. AGA and a number of pipeline operators opposed any requirement to pressure test all pipelines that have not been tested in accordance with subpart J, arguing Congress considered and rejected this approach in developing the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The commenters argue such a requirement would cripple the pipeline industry and support the alternative requirements included in the Act.

2. MidAmerican suggests a focus on pipe in Class 3 or 4 areas or HCAs. The company suggests no new requirements are needed if records are complete for pipe in these areas or it has been tested to 1.25 times MAOP. Otherwise, MidAmerican would subject such pipelines to a fitness for service determination.

3. The NTSB would require all pre-1970 pipelines to be pressure tested, including a spike test, citing their recommendation P–11–14.

4. Texas Pipeline Association and Texas Oil & Gas Association opposed a requirement to test all pipelines not previously subject to subpart J tests, arguing testing per the construction codes in effect when the pipelines were constructed and safe operating experience since then is adequate assurance of suitability.

5. Ameren Illinois reported the State of Illinois imposed pressure testing requirements before federal pipeline safety regulations were adopted in 1970.

6. Iowa Utilities Board and Iowa Association of Municipal Utilities recommended any new pressure test requirement be limited to pipeline segments in HCA and which operate at pressures where a rupture could occur (generally greater than 30 percent SMYS). These commenters argued the serious impacts of service interruptions pressure testing would be necessary for testing have not been appreciated and the cost for such testing of other pipelines would be unjustified absent any specific demonstration of risk.

7. Commissioners of Wyoming County Pennsylvania and Professional Engineers in California Government (PECG) would require pressure testing for pipelines not previously tested to subpart J requirements, since this would assure public safety. PECG would also require testing if adequate records of prior tests do not exist, noting California has experienced two failures to date of pipeline not adequately tested. PECG would also require all testing, modification, and replacement be observed by a certified inspector loyal to public safety interests.

8. An anonymous commenter would require subpart J testing but would allow schedule flexibility.

Response to Question N.3 Comments

PHMSA appreciates the information provided by the commenters. This NPRM proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). Verification of MAOP includes establishing and documenting MAOP using one or more of the methods in 192.624(c)(1) through (c)(6). In addition, this NPRM proposes requirements for verification of pipeline material in new § 192.607 for existing onshore, steel, gas transmission pipelines that are located in an HCA or class 3 or class 4 locations.

N.4. If a pipeline has pipe with a vintage history of systemic integrity issues in areas such as longitudinal

weld seams or steel quality, and has not been pressure tested at or above 1.1 times MAOP or class location test criteria (§§ 192.505, 192.619 and 192.620), should this pipeline be required to be pressure tested in accordance with present regulations?

1. AGA and several pipeline operators opposed requiring hydrostatic tests for systemic issues, arguing it could potentially affect all pipelines. AGA noted Congress had considered and rejected this approach in developing the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. AGA supports the requirements in Section 23 of the Act. AGA further argued hold times in subpart J are excessive since defects that fail will likely do so in the first 30 minutes and urged PHMSA not to require any special testing for pipelines operating at less than 30 percent SMYS since they are likely to fail by leakage rather than rupture.

2. GPTC and Nicor opposed a blanket requirement for hydrostatic testing. They would test only in event of a demonstrated safety issue and only if a risk evaluation indicates testing is appropriate. For distribution operators, these commenters would treat any safety issues in distribution integrity management programs.

3. Atmos would not require pressure testing for systemic issues, arguing these are addressed adequately by subpart O.

4. Accufacts would require testing, focusing first on pipe in HCAs, at pressures greater than 1.1 times MAOP. Accufacts understands some operators are arguing for a 1.1 x MAOP test pressure and considers that to be insufficient.

5. MidAmerican would allow a risk-based alternative approach for problem pipe.

6. Texas Pipeline Association and Texas Oil & Gas Association would require assessments appropriate to a specific threat rather than a blanket requirement for pressure testing.

7. An anonymous commenter supported pressure testing for pipe subject to systemic issues.

Response to Question N.4 Comments

PHMSA appreciates the information provided by the commenters. This NPRM proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3).

N.5. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

O. Modifying the Regulation of Gas Gathering Lines

The ANPRM requested comments regarding modifying the regulations relative to gas gathering lines. In March 2006, PHMSA issued new safety requirements for ''regulated onshore gathering lines.'' [38] Those requirements established a new method for determining if a pipeline is an onshore gathering line, divided regulated onshore gas gathering lines into two risk-based categories (Type A and Type B), and subjected such lines to certain safety standards.

The 2006 rule defined onshore gas gathering lines based on the provisions in American Petroleum Institute Recommended Practice 80, ''Guidelines for the Definition of Onshore Gas Gathering Lines,'' (API RP 80), a consensus industry standard incorporated by reference. Additional regulatory requirements for determining the beginning and endpoints of gathering, modifying the application of API RP 80, were also imposed to improve clarity and consistency in their application.

In practice, however, the use of API RP 80, even as modified by the additional regulations, is difficult for operators to apply consistently to complex gathering system configurations. Enforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system, which can lead to the potential misapplication of the incidental gathering line designation under that standard. In addition, recent developments in the field of gas exploration and production, such as shale gas, indicate that the existing framework for regulating gas gathering lines may need to be expanded. Gathering lines are being constructed to transport ''shale'' gas that range from 4 to 36 inches in diameter with MAOPs up to 1480 psig, far exceeding the historical operating parameters (pressure and diameter). The risks considered during the development of the 2006 rule did not foresee gathering lines of these diameters and pressures.

Currently, according to 2011 annual reports submitted by pipeline operators, PHMSA only regulates about 8845 miles of Type A gathering lines, 5178 miles of Type B gathering lines, and about 6258 miles of offshore gathering lines, for a total of approximately 20,281 miles of regulated gas gathering pipelines. Gas gathering lines are currently not regulated if they are in Class 1 locations. Current estimates also indicate that there are approximately 132,500 miles of Type A gas gathering lines located in Class 1 areas (of which approximately 61,000 miles are estimated to be 8-inch diameter or greater), and approximately 106,000 miles of Type B gas gathering lines located in Class 1 areas. Also, there are approximately 2,300 miles of Type B gas gathering lines located in Class 2 areas, some of which may not be regulated in accordance with § 192.8(b)(2).

The ANPRM then listed questions for consideration and comment. The following are general comments received related to this topic as well as comments related to the specific questions:

General Comments for Topic O

1. Gas Processors Association (GPA) recommended PHMSA complete the study required by Section 21 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 before proposing any substantive regulations regarding gathering lines. The Association sees this as an essential pre-requisite and indicated it would establish a working group to work with PHMSA on the study. Following the study, GPA would then have PHMSA begin any rulemaking process with another ANPRM, focused on the issues to be addressed in changing regulation of gathering lines. Independent Petroleum Association of America, American Petroleum Institute, Oklahoma Independent Petroleum Association, and Chevron agreed any change to gathering line regulations before the required report to Congress would be inconsistent with the Act.

2. Independent Petroleum Association of America, American Petroleum Institute, Oklahoma Independent Petroleum Association, and Chevron argued no change in the gathering line regulatory regime is justified. IPAA and API argued gathering lines can be regulated based only on actual, vs.

[38] 71 FR 13289 (March 15, 2006).

speculative, risk, and that any change without such demonstrated risk would be arbitrary, capricious, and contrary to law.

3. Atmos would require new gathering lines operating above 20 percent SMYS to meet requirements in § 192.9(c), and those below 20 percent SMYS § 192.9(d). These paragraphs are, respectively, requirements applicable to Type A and Type B gathering lines. The ''type'' of a gathering line is established in accordance with requirements in § 192.8, and is based on the pipe material and MAOP of the line. Atmos argued, however, that class location changes over time and determining applicable requirements for new gathering lines based on stress levels would provide for public safety without the problems or confusion that could result from subsequent class location changes.

4. Texas Pipeline Association and Texas Oil & Gas Association suggested PHMSA treat gathering lines under a separate docket and collect data under the current regulatory regime before making any changes. The associations suggested a delay in rulemaking of 3 to 5 years to accumulate data from recently-promulgated changes in reporting requirements. The associations argued changes made without gathering and reviewing that data could be found unnecessary and would divert resources from higher risk needs. Atmos agreed any rulemaking concerning gathering lines should be conducted under a separate docket due to the complexity of the issues involved.

5. Dominion East Ohio Gas argued it is too soon for wholesale changes to the new federal regulations applicable to gas gathering lines. The company suggested one proposed change would be to consider ''Incidental Gathering'' as defined in API RP 80.

6. NAPSR and Commissioners of Wyoming County Pennsylvania suggested PHMSA assert regulatory authority beginning at the wellhead or first metering point. They argued the regulatory gap that results from excluding production facilities from regulation produces risks, especially in areas where high-pressure wells are being drilled in urban areas. NAPSR further stated that PHMSA should consider short sections of pipeline downstream of processing, compression, and similar equipment to be a continuation of gathering. The functional name of a segment of pipeline is not important, *i.e.,* production, gathering, transmission. All pipelines should be treated the same in terms of safety from the well head to the city gate.

7. Commissioners of Wyoming County Pennsylvania recommended PHMSA regulate gathering lines in Class 1 areas. The Commissioners noted many new gathering lines, some operating at high pressures, are being constructed in Class 1 areas of the Marcellus Shale Region, and regulation of these lines is necessary to ensure public safety. The Commissioners noted Pennsylvania law gives the state's public utilities commission authority to regulate pipelines but requires that they be no more stringent than federal regulations.

8. The League of Women Voters of Pennsylvania would regulate gathering lines in the same manner as transmission and would further require that gas in pipelines of both types be odorized.

9. Pipeline Safety Trust would have PHMSA assure gathering lines are displayed on the National Pipeline Mapping System.

Response to General Comments for Topic O

PHMSA appreciates the information provided by the commenters. The commenters are correct that the Act required several actions related to gas gathering lines including a requirement that a study to be conducted prior to issuing new rules. We would note, however, that PHMSA is only proceeding with the issuance of an NPRM proposing expanded requirements and needed clarity with regard to issues that had been identified prior to enactment of the Act. The study has been completed and submitted to Congress and placed on the docket. PHMSA invites public comment on the study, which will inform the final rule. In addition, recent developments in the field of gas exploration and production, such as shale gas, indicate that the existing framework for regulating gas gathering lines may need to be expanded. Gathering lines are being constructed to transport ''shale'' gas that range from 4 to 36 inches in diameter with MAOPs up to 1,480 psig, far exceeding the historical operating parameters of such lines.

Currently, according to 2011 annual reports submitted by pipeline operators, PHMSA only regulates about 8845 miles of Type A gathering lines, 5,178 miles of Type B gathering lines, and about 6,258 miles of offshore gathering lines, for a total of approximately 20,281 miles of regulated gas gathering pipelines. Gas gathering lines are currently not regulated if they are in Class 1 locations. Current estimates also indicate that there are approximately 132,500 miles of Type A gas gathering lines located in Class 1 areas, and approximately 106,000 miles of Type B gas gathering lines located in Class 1 areas. Also, there are approximately 2,300 miles of Type B gas gathering lines located in Class 2 areas, some of which may not be regulated in accordance with § 192.8(b)(2).

Moreover, enforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system because numerous factors are involved, including the locations of treatment facilities, processing plants, and compressors, the relative spacing of production fields, and the commingling of gas. This can lead to the potential misapplication of the incidental gathering line designation under that standard.

In this NPRM, PHMSA proposes to extend existing requirements for Type B gathering lines to Type A gathering lines in Class 1 locations, if the nominal diameter is 8'' or greater.

Comments submitted for questions in Topic O.

O.1. Should PHMSA amend 49 CFR part 191 to require the submission of annual, incident, and safety-related conditions reports by the operators of all gathering lines?

1. AGA, GPTC, Texas Pipeline Association, Texas Oil & Gas Association, and several pipeline operators opposed requiring annual reports for unregulated gas gathering pipelines, arguing such a requirement would be unduly burdensome with no safety benefit. These commenters agreed incident reports for unregulated gathering lines could be useful as a means to determine the effectiveness of safety practices on these pipelines.

2. Gas Producers Association opposed expanding reporting requirements to Class 1 gathering pipelines. The Association noted gathering lines in other class locations are currently subject to reporting requirements and suggested there were other means for PHMSA to collect data on Class 1 lines without requiring burdensome reporting. In the specific case of safety-related condition reports, the Association argued requiring reporting is clearly premature, because the purpose of these reports is to highlight problems in which PHMSA may elect to become involved and PHMSA presently does not regulate these pipelines.

3. Texas Pipeline Association and Texas Oil & Gas Association would support requiring incidents to be reported for all gathering pipelines as a first step in collecting data to determine whether other changes are needed.

4. Atmos would support limited reporting for Class 1 gathering lines, to include incidents and total mileage.

5. NAPSR, Alaska Department of Natural Resources, Pipeline Safety Trust, and Commissioners of Wyoming County Pennsylvania would require operators of Class 1 gathering pipelines to submit reports, because these pipelines can affect public safety and should be held accountable.

Response to Question O.1 Comments

PHMSA appreciates the information provided by the commenters. The comments provide varied support for requiring submission of annual, incident, and safety-related conditions reports by the operators of all gathering lines. PHMSA believes these reports would provide valuable information, combined with the results of the congressionally required study, to support evaluation of the effectiveness of safety practices on these pipelines and determination of any needed additional requirements beyond those proposed in this NPRM. Accordingly, PHMSA proposes to delete the exemption for reporting requirements for operators of unregulated onshore gas gathering lines.

O.2. Should PHMSA amend 49 CFR part 192 to include a new definition for the term ''gathering line''?

1. AGA and several pipeline operators opposed a change to the definition of gathering lines, noting API RP–80, with restrictions as specified in current regulations, is a good working definition.

2. Independent Petroleum Association of America, American Petroleum Institute, Oklahoma Independent Petroleum Association, Atmos, and Chevron argued that API RP 80, as currently specified, is the appropriate means for defining gathering lines. They argued it is based on a pipeline's function rather than its location and changes could infringe on production facilities, regulation of which is precluded by statute.

3. Gas Processors Association opposed changing the definition of gathering line or extending regulation to lines in Class 1 areas. The Association noted excluding Class 1 lines from regulation is risk-based and expressed its interest in continuing the risk-based approach to regulation represented by the 2006 rule.

4. NAPSR, GPTC, Accufacts, Thomas Lael, and Nicor supported simplifying the definition of gathering lines. These commenters noted that API RP–80 is confusing. One commenter referred to its application as a ''nightmare.'' The definition in Texas regulations was suggested as one possible model.

5. Oklahoma Independent Petroleum Association strongly opposed changes to the definitions of gathering line or production facilities.

6. Texas Pipeline Association and Texas Oil & Gas Association would not change the definition of gathering lines at this time, arguing data gathering, a necessary first step, is not yet complete.

7. The State of Washington Citizens Advisory Committee and a private citizen urged changes to the definitions of gathering, transmission, and distribution pipelines, arguing that the current definitions are confusing and employ circular logic.

8. Pipeline Safety Trust would revise the definition of gathering in a manner that does not allow operators to choose whether their pipeline is gathering or not on the basis of where they decide to install equipment. PST noted there is significant overlap among pipeline types in size, operating pressure, and attendant risks.

9. Alaska Department of Natural Resources and Commissioners of Wyoming County Pennsylvania urged a revision to the definition of gathering lines, in light of shale gas development which, the commenters contended, produces risks approximately equivalent to those from transmission pipelines.

Response to Question O.2 Comments

PHMSA appreciates the information provided by the commenters. Industry commenters opposed a change to the definition of gathering lines, whereas NAPSR and other commenters supported revision of the definition of gathering lines and classified API RP–80 as confusing. As discussed above, PHMSA believes revision of the definition of gathering lines is needed and also proposes a new definition for onshore production facility/operation. In addition, see response to question O.3 comments.

O.3. Are there any difficulties in applying the definitions contained in RP 80? If so, please explain.

1. Independent Petroleum Association of America, American Petroleum Institute, Oklahoma Independent Petroleum Association, and Chevron were emphatic in declaring there are no difficulties in applying API RP–80. IPAA and API noted that significant difficulties among gathering lines made RP–80 difficult to develop.

2. AGA and a number of pipeline operators reported RP–80 is clear and there are no difficulties with its application.

3. Gas Processors Association would retain the RP–80 definition, at least until the study required by the Act is completed. GPA acknowledged that application of RP–80 has been difficult, but stated that it has been difficult to craft a simpler definition.

4. Texas Pipeline Association and Texas Oil & Gas Association reported application of RP–80 has been challenging. The associations opined this has resulted from complexities in gathering pipeline systems and confusion caused by PHMSA guidance and interpretations.

5. Accufacts, NAPSR, GPTC, and Nicor commented RP–80 is too complex, not understandable to the public, and subject to misuse by operators.

Response to Question O.3 Comments

PHMSA appreciates the information provided by the commenters. Industry commenters stated there are no difficulties in applying the definitions contained in API RP 80, whereas Accufacts, NAPSR and other commenters contend that API RP 80 is too complex, not understandable, and subject to misuse. PHMSA enforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, which is complex and can produce multiple classifications for the same pipeline system. In the 2006 rulemaking which incorporated by reference the API RP 80, PHMSA expressed reservations concerning the ability to effectively and consistently apply the document as written, echoing NAPSR's comments at the time. Additionally, in 2006, PHMSA imposed limiting regulatory language in part 192 in an attempt to curtail the potential for misapplication of the language contained in RP–80. These limitations and their intended application were discussed in great detail in the Supplemental Notice of Proposed Rulemaking [Docket No. RSPA–1998–4868; Notice 5]. Because of the ambiguous language and terminology in the RP–80, *e.g.* separators are defined for both production and gathering almost verbatim, experience has shown that facilities are being classified as production much further downstream than was ever intended. The application of ''incidental gathering'' as used in API RP–80 has not been applied as intended in some cases. Several recent interpretations letters have been issued by PHMSA on this topic including an expressed intent to clarify the issue in future rulemaking. Therefore, PHMSA believes revision of the definition of gathering lines is needed and proposes

deleting the use of API RP 80 as the basis for determining regulated gathering lines and would establish the new definition for onshore *production facility/operation* and a revised definition for *gathering line* as the basis for determining the beginning and endpoints of each gathering line.

O.4. Should PHMSA consider establishing a new, risk-based regime of safety requirements for large-diameter, high-pressure gas gathering lines in rural locations? If so, what requirements should be imposed?

1. Commissioners of Wyoming County Pennsylvania and 24 private citizens encouraged PHMSA to regulate gathering lines in Class 1 locations. The commenters noted many such pipelines will exist in shale gas areas, many of them large-diameter and operating at high pressures, and contended these pipelines currently are being ignored by federal and state regulators. They noted the pipeline that ruptured causing the San Bruno accident was operated at a pressure considerably lower than some gathering lines in shale gas areas.

2. AGA, GPTC, and a number of pipeline operators argued no new requirements are needed and the effectiveness of the 2006 changes to regulation needs to be reviewed first, in accordance with the Act.

3. Gas Processors Association, Texas Pipeline Association, and Texas Oil & Gas Association contended PHMSA must gather additional data on Class 1 gathering lines before deciding whether to regulate them, arguing that only a detailed study can determine whether new regulations are appropriate.

4. Oklahoma Independent Petroleum Association cautioned any regulatory change needs to be supported by science and a comprehensive cost-benefit analysis.

5. Independent Petroleum Association of America, American Petroleum Institute, Oklahoma Independent Petroleum Association, and Chevron argued any change in the regulatory regime for gathering lines is unjustified. The commenters contended such lines only operate at high pressures when new, that pressure decreases as wells deplete, and that the record shows these lines are safe.

6. A private citizen who operates an outdoor gear supply business in a shale gas region argued reduced use of recreational areas, caused by concerns over nearby pipelines, will adversely impact his and similar businesses.

7. Alaska Department of Natural Resources would establish risk-based safety requirements for gathering pipelines.

8. NAPSR would establish new, prescriptive requirements for large-diameter, high-pressure gathering lines.

9. Pipeline Safety Trust argued the composition of gas carried in many gathering lines leads to increased risk of corrosion and additional corrosion and testing requirements should thus be considered.

10. A private citizen, arguing for regulation of Class 1 gathering lines, noted experience has shown Class 1 locations change to Class 2 or 3 locations while the pipeline remains unchanged and, the commenter contended, unsafe.

11. Pipeline Safety Trust, Accufacts, and NAPSR would regulate gathering lines the same as transmission pipelines. PST would include integrity management requirements for lines operating at greater than 20 percent SMYS. NAPSR would impose IM if greater than 30 percent SMYS.

12. ITT Exelis Geospatial Systems contended that safety criteria applicable to a pipeline should be based on the specifications of the line.

Response to Question O.4 Comments

PHMSA appreciates the information provided by the commenters. The comments provide varied opinions for establishing new, risk-based safety requirements for gas gathering lines in rural locations. Several comments recommended PHMSA gather additional data on gathering lines before deciding to issue revised regulations. PHMSA believes rulemaking should proceed now to address the identified issues with regulation of gathering lines. Therefore, PHMSA proposes to extend existing requirements for Type B gathering lines to Type A gathering lines in Class 1 locations, if the nominal diameter is 8″ or greater. Integrity management requirements would not be applied to gathering lines at this time.

O.5. Should PHMSA consider short sections of pipeline downstream of processing, compression, and similar equipment to be a continuation of gathering? If so, what are the appropriate risk factors that should be considered in defining the scope of that limitation (*e.g.,* doesn't leave the operator's property, not longer than 1000 feet, crosses no public rights of way)?

1. The AGA, the GPTC, and a number of pipeline operators suggested that the piping mentioned in O.5 be considered as gathering. The commenters contended that this is clearly ''incidental gathering'' in API RP–80, particularly if below 20 percent SMYS, and that some agencies are presently treating this pipeline inappropriately as transmission pipeline.

2. Oleksa and Associates contended that the types of pipeline described in the question are ''incidental gathering.'' Oleksa argued that the length of these pipeline sections should not be the determining factor in their definition but, rather, risk elements and public safety impact should be afforded more importance.

3. The Gas Processors Association, the Texas Pipeline Association, and the Texas Oil & Gas Association would continue to treat these types of pipelines as gathering. They argued that this reflects the practical realities in the field regarding the ability to locate gathering-related equipment. GPA urged PHMSA to retain the concept of incidental gathering in any future change to the regulations, arguing this would continue a consistent regulatory approach to gathering pipelines.

4. The Independent Petroleum Association of America, the American Petroleum Institute, the Oklahoma Independent Petroleum Association, and Chevron contended that the safety record in the Barnett Shale area demonstrates further regulation of downstream pipelines and compression is not needed.

5. Commissioners of Wyoming County Pennsylvania would treat gathering lines as transmission lines, arguing that this would preclude the need to answer any of these questions.

6. The Delaware Solid Waste Authority (DSWA) argued for the continued treatment of the listed pipeline sections as part of gathering for landfill gas operations. DSWA noted that landfills may use intermediate compression to improve collection efficiency and may have pipe at pressure leading to flares etc.

7. Waste Management contended that piping that is an active part of a landfill gas collection and control system should be exempt from regulation as this piping is generally on landfill property and poses no risk to the public.

8. The National Solid Waste Management Association and Waste Management supported PHMSA's interpretation that pipelines operating at vacuum, such as landfill systems up to the compressor/blower should be unregulated.

Response to Question O.5 Comments

PHMSA appreciates the information provided by the commenters. See PHMSA's response to Question O.3, above.

O.6. Should PHMSA consider adopting specific requirements for pipelines associated with landfill gas

systems? If so, what regulations should be adopted and why? Should PHMSA consider adding regulations to address the risks associated with landfill gas that contains higher concentrations of hydrogen sulfide and/or carbon dioxide?

1. The AGA, the GPTC, and a number of pipeline operators contended that RP–80 makes clear that these pipelines are production piping and therefore regulation is prohibited. In addition, they argued that risk doesn't justify regulating these lines; the situation is similar to production and is already managed well. They also noted that landfill systems are generally constructed with non-corrosive materials. The commenters agreed that piping from landfills to transmission or distribution pipelines is gathering and should be regulated.

2. Oleksa and Associates contended that landfill pipelines are distribution pipelines, if they carry gas to end use customers.

3. The APGA argued that new requirements are appropriate, as landfill gas is different from natural gas. The APGA contended that application of current regulations often produces absurd results. APGA would add new requirements applicable to systems with high concentrations of hydrogen sulfide and allow systems with low concentrations to use current requirements.

4. The Delaware Solid Waste Authority argued that no new requirements are needed, because these systems operate at low pressures and existing requirements are sufficient.

5. NAPSR encouraged that PHMSA establish jurisdiction over and requirements for landfill gas systems, arguing that many operate as distribution pipelines. NAPSR also recommended that PHMSA develop requirements for odorizing landfill gas, since normal methods cannot be used.

6. The National Solid Waste Management Association and Waste Management argued that landfill gas lines under the control of a landfill operator or gas developer should remain unregulated because they pose minimal risk. They also contended that lines delivering landfill gas to distant users should also remain unregulated because they are mostly buried, are generally constructed of plastic pipe, and pose low risk due to low pressure, their dedicated nature, and lack of interconnects.

7. The National Solid Waste Management Association (NSWMA) noted that these pipelines are already regulated by the EPA and the states and argued that additional regulation would confer limited additional benefits. NSWMA argued that no requirements are needed to address internal corrosion, because these pipeline systems are generally constructed of plastic pipe and corrosive gas constituents are limited to prevent destruction of gas processing equipment. NSWMA suggested that PHMSA work with the EPA to obtain data on the landfill experience needed to support any future decision to regulate in this area.

8. Oleksa and Associates and the Delaware Solid Waste Authority would have PHMSA modify the regulations to clarify that pipe downstream of intermediate compression is unregulated, even if at pressure. They argued that the EPA has regulated such pipelines successfully and there is no safety case for applying part 192. DSWA further notes that most landfill pipeline is constructed of plastic pipe and not subject to internal corrosion.

9. Oleksa and Associates, the GPTC, Nicor, Waste Management, and the Delaware Solid Waste Authority would exempt landfill gas systems from requirements for odorization and odor sampling. They argued that there is a strong odor inherent to landfill gas, the sampling of which is not practical.

Response to Question O.6 Comments

PHMSA appreciates the information provided by the commenters. PHMSA is not proposing rulemaking to address landfill gas systems at this time, but would note that a pipeline that transports landfill gas away from the landfill facility to another destination is transporting gas. PHMSA will consider comments on this aspect of Topic O in the future.

O.7. Internal corrosion is an elevated threat to gathering systems due to the composition of the gas transported. Should PHMSA enhance its requirements for internal corrosion control for gathering pipelines? Should this include required cleaning on a periodic basis?

1. AGA, GPTC, and a number of pipeline operators commented that new requirements are not needed. They argued existing part 192 requirements are adequate for internal corrosion protection and unregulated gathering lines are rural and pose little risk.

2. AGA and a number of pipeline operators opposed a requirement for periodic cleaning of gathering lines. They noted existing lines are not configured to accommodate cleaning pigs and retrofitting them would be a major cost with no safety benefit.

3. Gas Producers Association noted internal corrosion is only one of many threats, existing regulations are adequate, and thus no new requirements are needed.

4. Texas Pipeline Association and Texas Oil & Gas Association opposed establishing internal corrosion requirements for gathering pipelines. The associations noted risk from IC is not prevalent for many gathering pipelines and suggested the need to collect data (*e.g.,* incidents) to determine whether new requirements are needed.

5. Accufacts would require, as a minimum, use of cleaning pigs and analysis of removed materials.

6. NAPSR, Alaska Department of Natural Resources, and Commissioners of Wyoming County Pennsylvania would enhance internal corrosion requirements and require periodic cleaning.

Response to Question O.7 Comments

PHMSA appreciates the information provided by the commenters. The majority of comments do not support enhancement of requirements for internal corrosion control for gathering pipelines. PHMSA is not proposing rulemaking specifically to address the need for additional internal corrosion requirements for gathering lines at this time. However, the proposed requirements in subpart I applicable to transmission lines; except the requirements in §§ 192.461(f), 192.465(f), 192.473(c) and 192.478, would be applicable to regulated Type A onshore gathering lines.

O.8. Should PHMSA apply its Gas Integrity Management Requirements to onshore gas gathering lines? If so, to what extent should those regulations be applied and why?

1. The AGA and several pipeline operators suggested that PHMSA consider applying some IM requirements to Type A gathering lines, since these lines represent conditions and risks similar to transmission pipelines. They consider IM inappropriate for Type B gathering lines, since these lines pose low risk and operate at hoop stresses similar to distribution pipelines.

2. The Gas Producers Association, the Texas Pipeline Association, the Texas Oil & Gas Association, and Atmos argued that it would be inappropriate to apply integrity management requirements to gathering pipelines. They noted that IM is a risk-based approach and that there is no evidence that gathering pipelines pose a risk that justifies application of IM.

3. The GPTC and Nicor opined that extending some aspects of gas transmission IM to non-rural, metallic

Type A gathering lines could provide enhanced protection to the public, since the operation and risk of these pipelines is similar to transmission pipelines. They cautioned, however, that the costs to impose IM on gathering pipelines would be significant. They considered IM inappropriate for Type B gathering lines since these lines are, by definition, of lower pressure and lower risk.

4. The Commissioners of Wyoming County Pennsylvania would apply IM to all onshore gathering pipelines. They would also apply requirements applicable to Class 2 transmission pipelines to Class 1 gathering pipelines, arguing that Class 1 areas will grow and class location will change.

5. Accufacts and the Alaska Department of Natural Resources would apply IM to gathering lines. Accufacts suggested an initial focus on large-diameter, high-pressure lines, since these lines are subject to failure by rupture.

Response to Question O.8 Comments

PHMSA appreciates the information provided by the commenters. PHMSA does not propose rulemaking to apply integrity management requirements to gathering lines at this time.

O.9. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

IV. Other Proposals

Inspection of Pipelines Following Extreme Weather Events.

Pipeline regulation prescribes requirements for the surveillance and periodic patrolling of the pipeline to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation, including unusual operating and maintenance conditions. The probable cause of the 2011 hazardous liquid pipeline accident resulting in a crude oil spill into the Yellowstone River near Laurel, Montana, is scouring at a river crossing due to flooding. This is a recent example of extreme weather that resulted in a pipeline incident. PHMSA has determined that additional regulations are needed to require, and establish standards for, the inspection of the pipeline and right-of-way for ''other factors affecting safety and operation'' following an extreme weather event such as a hurricane or flood, landslide, an earthquake, a natural disaster, or other similar event. The proposed rule would add a new paragraph (c) to section 192.613 to require such inspections, specify the timeframe in which such inspections should commence, and specify the appropriate remedial actions that must be taken to ensure safe pipeline operations. The new paragraph (c) would apply to onshore pipelines and their rights-of-way.

Notification for 7-Year Reassessment Interval Extension.

Section 5 of the Act identifies a technical correction amending Section 60109(c)(3)(B) of Title 49 of the United States Code to allow the Secretary of Transportation to extend the 7-year reassessment interval for an additional 6 months if the operator submits written notice to the Secretary justifying the need for the extension. PHMSA proposes to codify this statutory requirement.

Reporting Exceedances of Maximum Allowable Operating Pressure.

Section 23 of the Act requires operators to report each exceedance of the maximum allowable operating pressure (MAOP) that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. PHMSA proposes to codify this statutory requirement.

Consideration of Seismicity.

Section 29 of the Act states that in identifying and evaluating all potential threats to each pipeline segment, an operator of a pipeline facility must consider the seismicity of the area. PHMSA proposes to codify this statutory requirement to explicitly reference seismicity for data gathering and integration, threat identification, and implementation of preventive and mitigative measures.

Safety Features for In-line Inspection (ILI), Scraper, and Sphere Facilities.

PHMSA is proposing to add explicit requirements for safety features on launchers and receivers associated with ILI, scraper and sphere facilities.

Consensus Standards for Pipeline Assessments.

PHMSA is proposing to incorporate by reference consensus standards for assessing the physical condition of in-service pipelines using in-line inspection, internal corrosion direct assessment, and stress corrosion cracking direct assessment.

V. Section-by-Section Analysis

§ 191.1 Scope.

Section 191.1 prescribes requirements for the reporting of incidents, safety-related conditions, and annual pipeline summary data by operators of gas pipeline facilities. Currently, onshore gas gathering pipelines are exempt from reporting, as specified in paragraph (b)(4) of this section. In March 2012, the Government Accountability Office (GAO) issued a report (GAO–12–388) that contained a recommendation for DOT to collect data on federally unregulated hazardous liquid and gas gathering pipelines. PHMSA has determined that the statute requires the collection of additional information about gathering lines and that these reports and the congressionally required study support evaluation of the effectiveness of safety practices on these pipelines. Furthermore, PHMSA has inquired into whether any additional requirements are needed beyond those proposed in this NPRM. Accordingly, the proposed rule would repeal the exemption for reporting requirements for operators of unregulated onshore gas gathering lines by deleting § 191.1(b)(4), adding a new § 191.1(c), and making other conforming editorial amendments. In addition, Section 23 of the Act requires PHMSA to promulgate rules that require operators to report each exceedance of the maximum allowable operating pressure (MAOP) that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. The proposed rule would amend 191.1 to include MAOP exceedances within the scope of part 191.

§ 191.23 Reporting safety-related conditions.

Section 23 of the Act requires operators to report each exceedance of the maximum allowable operating pressure (MAOP) that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. On December 21, 2012, PHMSA published advisory bulletin ADB–2012–11, which advised operators of their responsibility under Section 23 of the Act to report such exceedances. PHMSA proposes to revise § 191.23 to codify this requirement.

§ 191.25 Filing safety-related condition reports.

Section 23 of the Act requires operators to report each exceedance of the maximum allowable operating pressure (MAOP) that exceeds the

margin (build-up) allowed for operation of pressure-limiting or control devices. As described above, PHMSA proposes to revise § 191.23 to codify this requirement. Section 191.25 would also be revised to provide consistent procedure, format, and structure for filing of such reports by all operators.

§ 192.3 Definitions.

Section 192.3 provides definitions for various terms used throughout part 192. In support of other regulations proposed in this NPRM, PHMSA is proposing to amend the definitions of ''*Electrical survey,*'' ''*(Onshore) gathering line,*'' and ''*Transmission line,*'' and add new definitions for ''*Close interval survey,*'' ''*Distribution center,* '' ''*Dry gas or dry natural gas,*'' ''*Gas processing plant,*'' ''*Gas treatment facility,*'' ''*Hard spot,*'' ''*In-line inspection (ILI),*'' ''*In-line inspection tool or instrumented internal inspection device,*'' ''*Legacy construction technique,*'' ''*Legacy pipe,*'' ''*Moderate consequence area,*'' ''*Modern pipe,*'' ''*Occupied site,*'' ''*Onshore production facility* or *onshore production operation,*'' ''*Significant Seam Cracking,*'' ''*Significant Stress Corrosion Cracking,*'' and ''*Wrinkle bend.*'' These changes will define these terms as used in the proposed changes to part 192. Many of the terms (such as in-line inspection, dry gas, hard spot, etc.) clarify technical definitions of terms used in part 192 or proposed in this rulemaking.

The revised definition for ''*(Onshore) gathering line,*'' and the new definitions for ''*Gas processing plant,*'' ''*Gas treatment facility,*'' and ''*Onshore production facility or onshore production operation,*'' are necessary because of ambiguous language and terminology in the current definition of regulated gas gathering lines, which invoke by reference API RP–80. The application of ''incidental gathering'' as used in API RP–80 has not been applied as intended in some cases. Several recent interpretation letters have been issued by PHMSA on this topic including an expressed intent to clarify the issue in future rulemaking. Therefore, PHMSA believes revision of the definition of gathering lines is needed and proposes repealing the use of API RP 80 as the basis for determining regulated gathering lines and would establish the new definition for ''*onshore production facility/operation, gas treatment facility, and gas processing plant,*'' and a revised definition for ''*(onshore) gathering line*'' as the basis for determining the beginning and endpoints of each gathering line.

The revised definition for ''*Electrical survey*'' aligns with the amended definition recommended in a petition dated March 26, 2012, from the Gas Piping Technology Committee (GPTC).

With regard to the new terms ''*moderate consequence area*'' or MCA, and ''*occupied site,*'' the definitions are based on the same methodology as ''*high consequence area*'' and ''*identified site*'' as defined in § 192.903. Moderate consequence areas will be used to define the subset of non-HCA locations where integrity assessments are required (§ 192.710), where material documentation verification is required (§ 192.607), and where MAOP verification is required (§§ 192.619(e) and 192.624). The criteria for determining MCA locations would use the same process and same definitions that are currently used to identify HCAs, except that the threshold for buildings intended for human occupancy and the threshold for persons that occupy other defined sites located within the potential impact radius would both be lowered from 20 to 5. This approach is proposed as a means to minimize the effort needed on the part of operators to identify the MCAs, since transmission operators must have already performed the analysis in order to have identified the HCAs or to verify that they have no HCAs. In response to NTSB recommendation P–14–01, which was issued as a result of the Sissonville, West Virginia incident, the MCA definition would also include locations where interstate highways, freeways, and expressways, and other principal 4-lane arterial roadways are located within the potential impact radius.

With regard to the new terms ''*legacy construction technique*'' and ''*legacy pipe,*'' the definitions are used in proposed and § 192.624 to identify pipe to which the proposed material verification and MAOP verification requirements would apply. The definitions are based on historical technical issues associated with past pipeline failures.

§ 192.5 Class locations.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that an important aspect of compliance with this requirement is to assure that pipeline class location records are complete and accurate. The proposed rule would add a new paragraph § 192.5(d) to require each operator of transmission pipelines to make and retain for the life of the pipeline records documenting class locations and demonstrating how an operator determined class locations in accordance with this section.

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

Section 192.7 lists documents that are incorporated by reference in part 192. PHMSA proposes conforming amendments to § 192.7 in the rule text to reflect other changes proposed in this NPRM.

§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

Section 192.8 defines the upstream and downstream endpoints of gas gathering pipelines. Recent developments in the field of gas exploration and production, such as shale gas, indicate that the existing framework for regulating gas gathering lines may no longer be appropriate. Gathering lines are being constructed to transport ''shale'' gas that range from 4 to 36 inches in diameter with MAOPs of up to 1480 psig, far exceeding the historical operating parameters of such lines.

Currently, according to the 2011 annual reports submitted by pipeline operators, PHMSA only regulates about 8,845 miles of Type A gathering lines, 5,178 miles of Type B gathering lines, and about 6,258 miles of offshore gathering lines, for a total of approximately 20,281 miles of regulated gas gathering pipelines. Gas gathering lines are currently not regulated if they are in Class 1 locations. Current estimates also indicate that there are approximately 132,500 miles of Type A gas gathering lines located in Class 1 areas (of which approximately 61,000 miles are estimated to be 8-inch diameter or greater), and approximately 106,000 miles of Type B gas gathering lines located in Class 1 areas. Also, there are approximately 2,300 miles of Type B gas gathering lines located in Class 2 areas, some of which may not be regulated in accordance with § 192.8(b)(2).

Moreover, enforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system. PHMSA has also identified a regulatory gap that permits the potential misapplication of the incidental gathering line designation under that standard. Consequently, to address these issues and gaps, the proposed rule would repeal the use of API RP 80 as the basis for determining regulated gathering lines and would establish a new definition for onshore production facility/operation and a

revised definition for gathering line as the basis for determining the beginning and endpoints of each gathering line. The definition of onshore production facility/operation includes initial preparation of gas for transportation at the production facility, including separation, lifting, stabilizing, and dehydration. Pipelines commonly referred to as ''farm taps'' serving residential/commercial customers or industrial customers are not classified as gathering, but would continue to be classified as transmission or distribution as defined in § 192.3.

§ 192.9 What requirements apply to gathering lines?

Section 192.9 identifies those portions of part 192 that apply to regulated gas gathering lines. For the same reasons discussed under § 192.8, above, the proposed rule would expand and clarify the requirements that apply to gathering lines. PHMSA proposes to extend existing regulatory requirements for Type B gathering lines to Type A gathering lines in Class 1 locations, if the nominal diameter of the line is 8″ or greater.

In addition, on August 20, 2014, the GAO released a report (GAO Report 14–667) to address the increased risk posed by new gathering pipeline construction in shale development areas. GAO recommended that a rulemaking be pursued for gathering pipeline safety that addresses the risks of larger-diameter, higher-pressure gathering pipelines, including subjecting such pipelines to emergency response planning requirements that currently do not apply. Currently, Type A gathering lines are subject to the emergency planning requirements in § 192.615 and only include gathering lines in Class 2, 3, and 4 locations that have a Maximum Allowable Operating Pressure (MAOP) with a hoop stress of 20% or more for metallic pipe and MAOP of more than 125 psig for non-metallic pipe. Further, gathering lines that are located in Class 1 areas (*e.g.,* rural areas) are not considered Type A gathering lines even if they meet the pressure criteria specified in the preceding sentence. PHMSA is proposing to create sub-divisions of Type A gathering lines (Type A, Area 1 and Type A, Area 2). The new designation ''Type A, Area 1 gathering lines'' would apply to currently regulated Type A gathering lines. The new designation ''Type A, Area 2 gathering lines'' would apply to gathering lines with a diameter of 8-inch or greater that meet all of the qualifying parameters for currently regulated Type A gathering, but are located in Class 1 locations. PHMSA proposes to address the GAO recommendation by requiring the newly proposed Type A, Area 2 regulated onshore gathering lines, which include lines in Class 1 locations with a nominal diameter of 8-inch or greater, to develop procedures, training, notifications, and carry out emergency plans as described in § 192.615, in addition to a limited set of other specific requirements, including corrosion protection and damage prevention.

§ 192.13 General.

Section 192.13 prescribes general requirements for gas pipelines. PHMSA has determined that safety and environmental protection would be improved by generally requiring operators to evaluate and mitigate risks during all phases of the useful life of a pipeline as an integral part of managing pipeline design, construction, operation, maintenance and integrity, including management of change. This proposed rule would add a new paragraph (d) to establish a general clause requiring onshore gas transmission pipeline operators to evaluate and mitigate risks to the public and environment as part of managing pipeline design, construction, operation, maintenance, and integrity, including management of change. The new paragraph would also invoke the requirements for management of change as outlined in ASME/ANSI B31.8S, section 11, and explicitly articulate the requirements for a management of change process that are applicable to onshore gas transmission pipelines.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that an important aspect of compliance with this requirement is to assure that records that demonstrate compliance with part 192 are complete and accurate. The proposed rule would add a new paragraph (e) that clearly articulates the requirements for records preparation and retention and requires that records be reliable, traceable, verifiable, and complete. Further, the proposed Appendix A would provide specific requirements for records retention for transmission pipelines.

In addition, conforming amendments to paragraphs (a) and (b) list the effective date of the proposed requirements for newly regulated onshore gathering lines.

§ 192.67 Records: Materials.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline material records are complete and accurate. The proposed rule would add a new § 192.67 to require each operator of transmission pipelines to make and retain for the life of the pipeline the original steel pipe manufacturing records that document tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured.

§ 192.127 Records: Pipe design.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipe design records are complete and accurate. The proposed rule would add a new § 192.127 to require each operator of transmission pipelines to make and retain for the life of the pipeline records documenting pipe design to withstand anticipated external pressures and determination of design pressure for steel pipe.

§ 192.150 Passage of internal inspection devices.

The current pipeline safety regulations in 49 CFR 192.150 require that pipelines be designed and constructed to accommodate in-line inspection devices. Part 192 is silent on technical standards or guidelines for implementing requirements to assure pipelines are designed and constructed for ILI assessments. At the time these rules were promulgated, there was no consensus industry standard that addressed design and construction requirements for ILI. NACE Standard Practice, NACE SP0102–2010, ''In-line Inspection of Pipelines,'' has since been published and provides guidance in this area in Section 7. The incorporation of this standard into § 192.150 will promote a higher level of safety by establishing consistent standards for the design and construction of line pipe to accommodate ILI devices.

§ 192.205 Records: Pipeline components.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline component records are complete and

accurate. The proposed rule would add a new § 192.205 to require each operator of transmission pipelines to make and retain records documenting manufacturing and testing information for valves and other pipeline components.

§ 192.227 Qualification of welders.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline welding records are complete and accurate. The proposed rule would add a new paragraph § 192.227(c) to require each operator of transmission pipelines to make and retain for the life of the pipeline records demonstrating each individual welder qualification in accordance with this section.

§ 192.285 Plastic pipe: Qualifying persons to make joints.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline qualification records are complete and accurate. The proposed rule would add a new paragraph § 192.285(e) to require each operator of transmission pipelines to make and retain for the life of the pipeline records demonstrating plastic pipe joining qualifications in accordance with this section.

§ 192.319 Installation of pipe in a ditch.

Section 192.319 prescribes requirements for installing pipe in a ditch, including requirements to protect pipe coating from damage during the process. However, during handling, lowering, and backfilling, sometimes pipe coating is damaged, which can compromise its ability to protect against external corrosion. An example of the consequences of such damage occurred in 2011 on the Bison Pipeline, operated by TransCanada Northern Border Pipeline, Inc. In this case, the probable cause of the incident was attributed to latent coating and mechanical damage caused during construction, which subsequently caused the pipeline to fail. To help prevent recurrence of such incidents, PHMSA has determined that additional requirements are needed to verify that pipeline coating systems for protection against external corrosion are not damaged during the installation and backfill process. Accordingly, this proposed rule would add a new paragraph (d) to require that onshore gas transmission operators perform an above-ground indirect assessment to identify locations of suspected damage promptly after backfill is completed and remediate any moderate or severe coating damage. Mechanical damage is also detectable by these indirect assessment methods, since the forces that are able to mechanically damage steel pipe usually result in detectable coating defects. Paragraph (d) does not apply to gas gathering lines or distribution mains. In addition, paragraph (d) would require each operator of transmission pipelines to make and retain for the life of the pipeline records documenting the coating assessment findings and repairs.

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

Section 192.452 prescribes corrosion control requirements for regulated onshore gathering lines. PHMSA proposes conforming amendments to the rule text in paragraph (b) to reflect other changes proposed in this NPRM for gas gathering lines.

§ 192.461 External corrosion control: Protective coating.

Section 192.461 prescribes requirements for protective coating systems. However, certain types of coating systems that have been used extensively in the pipeline industry can impede the process of cathodic protection if the coating disbonds from the pipe. The NTSB determined that this was a significant contributing factor in the major crude oil spill that occurred near Marshall, Michigan, in 2010. PHMSA has determined that additional requirements are needed to specify that coating should not impede cathodic protection and to ensure operators verify that pipeline coating systems for protection against external corrosion have not become compromised or damaged during the installation and backfill process. Accordingly, this proposed rule would amend paragraph (a)(4) to require that coating have sufficient strength to resist damage during installation and backfill, and add a new paragraph (f) to require that onshore gas transmission operators perform an above-ground indirect assessment to identify locations of suspected damage promptly after backfill is completed or anytime there is an indication that the coating might be compromised. It would also require prompt remediation of any moderate or severe coating damage.

§ 192.465 External corrosion control: Monitoring.

Section 192.465 currently prescribes that operators monitor cathodic protection and take prompt remedial action to correct deficiencies indicated by the monitoring. The provisions in § 192.465 do not specify the remedial actions required to correct deficiencies and do not define ''prompt.'' To address this potential issue, the proposed rule would amend paragraph (d) to require that remedial action must be completed promptly, but no later than the next monitoring interval specified in § 192.465 or within one year, whichever is less. In addition, a new paragraph (f) is added to require onshore gas transmission operators to perform close-interval surveys if annual test station readings indicate cathodic protection is below the level of protection required in subpart I. Unless it is impractical to do so, close interval surveys must be completed with the protective current interrupted. Impracticality must be based on a technical reason, for example, a pipeline protected by direct buried sacrificial anodes (anodes directly connected to the pipeline), and not on cost impact. The proposed rule would also require each operator to take remedial action to correct any deficiencies indicated by the monitoring.

§ 192.473 External corrosion control: Interference currents.

Interference currents can negate the effectiveness of cathodic protection systems. Section 192.473 prescribes general requirements to minimize the detrimental effects of interference currents. However, specific requirements to monitor and mitigate detrimental interference currents have not been prescribed in subpart I. In 2003, PHMSA issued advisory bulletin ADB–03–06 (68 FR 64189). The bulletin advised each operator of a natural gas transmission or hazardous liquid pipeline to determine whether new steel pipelines are susceptible to detrimental effects from stray electrical currents. Based on this evaluation, an operator should carefully monitor and take action to mitigate detrimental effects. The operator should give special attention to a new pipeline's physical location, particularly where that location may subject the new pipeline to stray currents from other underground facilities, including other pipelines or induced currents from electrical transmission lines, whether aboveground or underground. Operators were strongly encouraged to review their corrosion control programs and to have qualified corrosion personnel present during construction to identify, mitigate, and monitor any detrimental stray currents that might damage new

pipelines. Since the advisory bulletin, PHMSA continues to identify cases where significant pipeline defects are attributed to corrosion caused by interference currents. Examples include CenterPoint Energy's CP line (2007), Keystone Pipeline (2012) and Overland Pass Pipeline (2012). Therefore, PHMSA has determined that additional requirements are needed to explicitly require that operators conduct interference surveys and to timely remediate adverse conditions. The proposed rule would add new paragraph (c) to require that onshore gas transmission operator programs include interference surveys to detect the presence of interference currents and to require taking remedial actions promptly after completion of the survey to adequately protect the pipeline segment from detrimental interference currents, but no later than 6 months in any case.

§ 192.478 Internal corrosion control: Monitoring.

Section 192.477 prescribes requirements to monitor internal corrosion if corrosive gas is being transported. However, the existing rules do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system changes, changing gas supply, upset conditions, or other changes. This could result in pipelines that are not monitored for internal corrosion, because an initial assessment did not identify the presence of corrosive gas. In September 2000, following the Carlsbad explosion, PHMSA issued Advisory Bulletin 00–02, dated 9/1/2000 (65 FR 53803). The bulletin advised owners and operators of natural gas transmission pipelines to review their internal corrosion monitoring programs and consider factors that influence the formation of internal corrosion, including gas quality and operating parameters. Pipeline operators continue to report incidents attributed to internal corrosion. Between 2002 and November 2012, 206 incidents have been reported that were attributed to internal corrosion. PHMSA has determined that additional requirements are needed to assure that operators effectively monitor gas stream quality to identify if and when corrosive gas is being transported and to mitigate deleterious gas stream constituents (*e.g.,* contaminants or liquids). The proposed rule would add the new section 192.478 to require monitoring for deleterious gas stream constituents for onshore gas transmission operators, and require that gas monitoring data be evaluated quarterly. In addition, the proposed rule would add a requirement for onshore gas transmission operators to review the internal corrosion monitoring and mitigation program semi-annually and adjust the program as necessary to mitigate the presence of deleterious gas stream constituents. This is in addition to existing requirements to check coupons or other means to monitor for the actual presence of internal corrosion in the case of transporting a known corrosive gas stream.

§ 192.485 Remedial measures: Transmission lines.

Section 192.485 prescribes requirements for remedial measures to address general corrosion and localized corrosion pitting in transmission lines. For such conditions it specifies that the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3–805 (RSTRENG). PHMSA has determined that additional requirements are needed to assure such calculations have a sound basis. The proposed rule would revise section 192.485(c) to specify that pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.

§ 192.493 In-line inspection of pipelines.

The current pipeline safety regulations in 49 CFR 192.921 and 192.937 require that operators assess the material condition of pipelines in certain circumstances (*e.g.,* IM assessments for pipelines that could affect high consequence areas) and allow use of in-line inspection tools for these assessments. Operators of gas transmission pipelines are required to follow the requirements of ASME/ANSI B31.8S, ''Managing System Integrity of Gas Pipelines,'' in conducting their IM activities. ASME B31.8S provides limited guidance for conducting ILI assessments. Part 192 is silent on technical standards or guidelines for performing ILI assessments or implementing these requirements. At the time these rules were promulgated, there was no consensus industry standard that addressed ILI. Three related standards have since been published:

- API STD 1163–2005, ''In-Line Inspection Systems Qualification Standard.'' This Standard serves as an umbrella document to be used with and complement the NACE and ASNT standards below, which are incorporated by reference in API STD 1163.
- NACE Standard Practice, NACE SP0102–2010, ''In-line Inspection of Pipelines.''
- ANSI/ASNT ILI–PQ–2010, ''In-line Inspection Personnel Qualification and Certification.''

The API standard is more comprehensive and rigorous than requirements currently incorporated into 49 CFR part 192. The incorporation of this standard into pipeline safety regulations will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes and software utilized by the in-line inspection industry. The API standard addresses in detail each of the following aspects of ILI inspections, most of which are not currently addressed in the regulations:

- Systems qualification process
- Personnel qualification
- In-line inspection system selection
- Qualification of performance specifications
- System operational validation
- System Results qualification
- Reporting requirements
- Quality management system

The incorporation of this standard into pipeline safety regulations will promote a higher level of safety by establishing consistent standards for conducting ILI assessments of line pipe. The NACE standard covers in detail each of the following aspects of ILI assessments, most of which are not currently addressed in part 192 or in ASME B31.8S:

- Tool selection
- Evaluation of pipeline compatibility with ILI
- Logistical guidelines, which includes survey acceptance criteria and reporting
- Scheduling
- New construction (planning for future ILI in new lines)
- Data analysis
- Data management
- The NACE standard provides a standardized questionnaire and specifies that the completed questionnaire should be provided to the ILI vendor. The questionnaire lists relevant parameters and characteristics of the pipeline section to be inspected.

PHMSA believes that the consistency, accuracy and quality of pipeline in-line inspections would be improved by incorporating the consensus NACE standard into the regulations.

The NACE standard applies to ''free swimming'' inspection tools that are carried down the pipeline by the

transported fluid. It does not apply to tethered or remotely controlled ILI tools, which can also be used in special circumstances (*e.g.,* examination of laterals). While their use is less prevalent than free swimming tools, some pipeline IM assessments have been conducted using these tools. PHMSA considers that many of the provisions in the NACE standard can be applied to tethered or remotely controlled ILI tools. Therefore, PHMSA is proposing to allow the use of these tools, provided they generally comply with the applicable sections of the NACE standard.

The ANSI/ASNT standard provides for qualification and certification requirements that are not addressed by 49 CFR part 192. The incorporation of this standard into pipeline safety regulations will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes and software utilized by the in-line inspection industry. The ANSI/ASNT standard addresses in detail each of the following aspects, which are not currently addressed in the regulations:

• Requirements for written procedures
• Personnel qualification levels
• Education, training and experience requirements
• Training programs
• Examinations (testing of personnel)
• Personnel certification and recertification
• Personnel technical performance evaluations

The proposed rule adds a new § 192.493 to require compliance with the requirements and recommendations of the three consensus standards discussed above when conducting in-line inspection of pipelines.

§ 192.503 General requirements.

Section 192.503 prescribes the general test requirements for the operation of a new segment of pipeline, or returning to service a segment of pipeline that has been relocated or replaced. The proposed rule would add additional requirements to § 192.503(a)(1) to reflect other requirements for determination of MAOP. These include § 192.620 for alternative MAOP determination requirements and new § 192.624 for verification of MAOP for onshore, steel, gas transmission pipeline segments that: (1) Has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs''); (2) Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; or (ii) a class 3 or class 4 location; or (3) the pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before *[effective date of rule]* and is located in one of the following areas: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

§ 192.506 Transmission lines: Spike hydrostatic pressure test for existing steel pipe with integrity threats.

The NTSB recommended repealing § 192.619(c) and requiring that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test (recommendation P–11–14). Currently, part 192 does not contain any requirement for operators to conduct spike hydrostatic pressure tests. In response to the NTSB recommendation, this NPRM proposes requirements for verification of MAOP in new § 192.624, which requires that MAOP be established and documented for pipelines located in either an HCA or MCA meeting the conditions in § 192.624(a)(1) through (3) using one or more of the methods in § 192.624(c)(1) through (6). The pressure test method requires performance of a spike pressure test in accordance with new § 192.506 if the pipeline includes legacy pipe or was constructed using legacy construction techniques or if the pipeline has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking.

§ 192.517 Records.

Section 192.517 prescribes the record requirements for each test performed under §§ 192.505 and 192.507. The proposed rule would revise § 192.517 to add the record requirements for § 192.506.

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

Section 192.605 prescribes requirements for the operator's procedural manual for operations, maintenance, and emergencies. Part 192 contains numerous requirements intended to protect pipelines from overpressure events. These include mandatory pressure relieving or pressure limiting devices, inspections and tests of such devices, establishment of maximum allowable operating pressure, and administrative requirements to not operate the pipeline at pressures that exceed the MAOP, among others. Implicit in the requirements of § 192.605 is the intent for operators to establish operational and maintenance controls and procedures to effectively implement these requirements and preclude operation at pressures that exceed MAOP. PHMSA expects that operator's procedures should already address this aspect of operations and maintenance, as it is a long-standing, critical aspect of safe pipeline operations. However, § 192.605 does not explicitly prescribe this aspect of the procedural controls. In addition, as a result of the San Bruno incident, Congress mandated in Section 23 of the Act that any exceedance of MAOP on a gas transmission pipeline be reported to PHMSA. As part of such reporting, the operator should inform PHMSA of the cause(s) of each exceedance. On December 21, 2012, PHMSA published advisory bulletin ADB–2012–11, which advised transmission operators of their responsibility under Section 23 of the Act to report exceedances of MAOP that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices (*i.e.,* report any pressure exceedances over the pressure limiting or control device set point as defined in applicable sections of §§ 192.201(a)(2) or 192.739). Between December 21, 2012 and June 30, 2013, PHMSA received 14 such notifications. Therefore, PHMSA has determined that an additional requirement is needed to explicitly require procedures to maintain and operate pressure relieving devices and to control operating pressure to prevent

exceedance of MAOP. The proposed rule clarifies the existing requirements regarding such procedural controls.

§ 192.607 Verification of pipeline material: Onshore steel transmission pipelines.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of the pipelines and to confirm the established MAOP of the pipelines. PHMSA issued Advisory Bulletin 11–01 on January 10, 2011 (76 FR 1504) and Advisory Bulletin 12–06 on May 7, 2012 (77 FR 26822) to inform operators of this requirement. Operators have submitted information in their 2012 Annual Reports indicating that a portion of transmission pipeline segments do not have adequate records to establish MAOP or to accurately reflect the physical and operational characteristics of the pipeline. Therefore, PHMSA has determined that additional rules are needed to implement this requirement of the Act. Specifically, PHMSA has determined that additional rules are needed to require that operators conduct tests and other actions needed to understand the physical and operational characteristics for those segments where adequate records are not available, and to establish standards for performing these actions.

This issue was addressed in detail at the Integrity Verification Process workshop on August 7, 2013. Major issues that were discussed include the scope of information needed and the methodology for verifying material properties. The most difficult information to obtain, from a technical perspective, is the strength of the steel. Conventional techniques would include cutting out a piece of pipe and destructively testing it to determine yield and ultimate tensile strength. PHMSA proposes to address this in the rule by allowing new non-destructive techniques if they can be validated to produce accurate results for the grade and type of pipe being evaluated. Such techniques have already been successfully validated for some grades of pipe.

Another issue is the extremely high cost of excavating the pipeline in order to verify the material, and determining how much pipeline needs to be exposed and tested in order to have assurance of pipeline properties. PHMSA proposes to address this issue by specifying that operators take advantage of opportunities when the pipeline is exposed for other reasons, such as maintenance and repair, by requiring that material properties be verified whenever the pipe is exposed. Over time, pipeline operators will develop a substantial set of verified material data, which will provide assurance that material properties are reliably known for the entire population of inadequately documented segments. PHMSA proposes to require that operators continue this opportunistic material verification process until the operator has completed enough verifications to obtain high confidence that only a small percentage of inadequately documented pipe lengths have properties that are inconsistent with operators' past assumptions. The rule would specify the number of excavations required to achieve this level of confidence.

Lastly, PHMSA proposes criteria that would require material verification for higher risk locations. Therefore, the proposed rule would add requirements for verification of pipeline material in new § 192.607 for existing onshore, steel, gas transmission pipelines that are located in an HCA or a class 3 or class 4 location. PHMSA believes this approach appropriately addresses pipeline segment risk without extending the requirement to all pipelines where risk and potential consequences are not as significant, such as pipeline in remote rural areas.

Requirements are also included to ensure that the results of this process are documented in records that are reliable, traceable, verifiable, and complete that must be retained for the life of the pipeline.

§ 192.613 Continuing surveillance.

Section 192.613 prescribes general requirements for continuing surveillance of the pipeline to determine and take action due to changes in the pipeline from, among other things, unusual operating and maintenance conditions. The 2011 hazardous liquid pipeline accident resulting in a crude oil spill into the Yellowstone River near Laurel, Montana was probably caused by scouring at a river crossing due to flooding. Based on recent examples of extreme weather events that did result, or could have resulted, in pipeline incidents, PHMSA has determined that additional requirements are needed to assure that operator procedures adequately address inspection of the pipeline and right-of-way for ''other factors affecting safety and operation'' following an extreme weather event such as a hurricane or flood, landslide, an earthquake, a natural disaster, or other similar event. The proposed rule would add a new paragraph (c) to require such inspections, specify the timeframe in which such inspections should commence, and specify the appropriate remedial actions must be taken to ensure safe pipeline operations. The new paragraph (c) would apply to both onshore transmission pipelines and their rights-of-way.

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

The NTSB issued its report on the San Bruno incident that included a recommendation (P–11–15) that PHMSA amend its regulations so that manufacturing and construction-related defects can only be considered ''stable'' if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP. This NPRM proposes to revise the test pressure factors in § 192.619(a)(2)(ii) to correspond to at least 1.25 MAOP for newly installed pipelines.

In addition, Section 23 of the Act requires verification of records to confirm the established MAOP of the pipelines. Operators have submitted information in their 2012 Annual Reports indicating that a portion of gas transmission pipeline segments do not have adequate records to establish MAOP. For pipelines without an adequately documented basis for MAOP, the proposed rule adds a new paragraph (e) to § 192.619 to require that certain onshore steel transmission pipelines that meet the criteria specified in § 192.624(a), and that do not have adequate records to establish MAOP, must establish and document MAOP in accordance with new § 192.624 using one or more of the methods in § 192.624(c)(1) through (6), as discussed in more detail below.

The proposed rule would also add a new paragraph (f) to explicitly require that records documenting tests, design, and other information necessary to establish MAOP be retained for the life of the pipeline.

Lastly, the rule would incorporate conforming changes to § 192.619(a) to reflect changes to gas gathering regulations proposed in §§ 192.8 and 192.9.

§ 192.624 Maximum allowable operating pressure verification: Onshore steel transmission pipelines.

Section 23 of the Act requires verification of records used to establish MAOP for pipe in class 3 and class 4 locations and high-consequence areas in Class 1 and 2 locations to ensure they accurately reflect the physical and operational characteristics of the pipelines and to confirm the established MAOP of the pipelines. Operators have submitted information in their 2012 Annual Reports indicating that some gas transmission pipeline segments do not

have adequate records or testing to establish MAOP. For pipelines so identified, the Act requires that PHMSA promulgate regulations to require operators to test the segments to confirm the material strength of the pipe in HCAs that operate at stress levels greater than or equal to 30% SMYS. Such tests must be performed by pressure testing or other methods determined by the Secretary to be of equal or greater effectiveness.

As a result of its investigation of the San Bruno accident, NTSB issued two related recommendations. NTSB recommended that PHMSA repeal § 192.619(c) and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test (P–11–14). NTSB also recommended that PHMSA amend the Federal pipeline safety regulations so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure (P–11–15).

The proposed rule would add a new § 192.624 to address these mandates and recommendations. The rule would require that operators re-establish and document MAOP for certain onshore steel transmission pipelines located in an HCA or MCA that meet one or more of the criteria specified in § 192.624(a). Those criteria include: (1) Has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs''); (2) Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; or (ii) a class 3 or class 4 location; or (3) the pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before *[effective date of rule]* and is located in one of the following areas: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

The methods specified in § 192.624 include the pressure test method. If the pipeline includes legacy pipe or was constructed using legacy construction techniques or the pipeline has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, a spike pressure test in accordance with new § 192.506 would be required. For modern pipe without the aforementioned risk factors, a pressure test in accordance with § 192.505 would be allowed.

Other methods to reestablish MAOP for pipe currently operating under § 192.619(c) would also be allowed. PHMSA has determined that the following methods would provide equal or greater effectiveness as a pressure test:

(i) De-rating the pipe segment such that the new MAOP is less than historical actual sustained operating pressure by using a safety factor of 0.80 times the sustained operating pressure (equivalent to a pressure test using gas or water as the test medium with a test pressure of 1.25 times MAOP). For segments that operate at stress levels of less than 30% SMYS a safety factor of 0.90 times sustained operating pressure is allowed (equivalent to a pressure test of 1.11 times MAOP), supplemented with additional integrity assessments, and preventive and mitigative measures specified in the proposed rule.

(ii) Replacement of the pipe, which would require a new pressure test that conforms with subpart J before being placed in service,

(iii) An in-line inspection and Engineering Critical Assessment process using technical criteria to establish a safety margin equivalent to that provided by a pressure test, or

(iv) Use of other technology that the operator demonstrates provides an equivalent or greater level of safety, provided PHMSA is notified in advance.

The proposed rule establishes requirements for pipelines operating at stress levels of less than 30% of SMYS based on technical information provided in Interstate Natural Gas Association of America/American Gas Association Final Report No. 13–180, ''Leak vs. Rupture Thresholds for Material and Construction Anomalies,'' December 2013. The report references a 2010 study by Kiefner & Associates, Inc. ''Numerical Modeling and Validation for Determination of the Leak/Rupture Boundary for Low-Stress Pipelines'' performed under contract to the Gas Technology Institute (GTI). The Kiefner/GTI report evaluated theoretical fracture models and supporting test data in order to define a possible leak-rupture threshold stress level. The report pointed out that ''no evidence was found that a propagating ductile rupture could arise from an incident attributable to any one of these causes in a pipeline that is being operated at a hoop stress level of 30% of SMYS or less.'' In addition, the INGAA/AGA report included a review of Kiefner & Associates, Inc. failure investigation reports, which concluded that all manufacturing related defects failing under the action of hoop stress alone failed as leaks if the hoop stress level was 30% SMYS or less except for one case out of 94 which failed at 27% of SMYS. The INGAA/AGA report states that a hydrostatic test to 1.25 times the MAOP is unnecessary to reasonably assure stability of pipe manufacturing construction related features in pipe meeting the following conditions: (1) Ductile fracture initiation is assured by showing that the pipe has an operating temperature above the brittle fracture initiation temperature; (2) interaction with in-service degradation mechanics such as selective seam weld corrosion or previous mechanical damage is absent; (3) hoop stress is 30% or less; (4) mill pressure testing was conducted at 60% SMYS or more, established by documented conformance to applicable pipe product specifications (*e.g.,* API 5L) or company specifications; and (5) pipe is 6 NPS or smaller. For pipes that are 8 NPS or larger but still meeting the conditions mentioned above, hydrostatic pressure testing to 1.25 times the MAOP is still prudent, since theoretical analysis as well as full scale laboratory tests show that failure as a rupture is possible for stress thresholds below 30% of SMYS. However, NPS 8 pipe may be prioritized lower than larger pipe because there were no reported incidents of service rupture in pipe that size where all other criteria were met. PHMSA plans to limit stress levels, pressures, and pipe diameters that can meet the potential impact

radius and require alternative integrity and preventative and mitigative measures for pipelines that use these criteria to establish MAOP.

The above approach implements the regulatory mandate in the Act for segments in HCAs. In addition, the scope includes additional pipe segments in the newly defined moderate consequence areas. This approach is intended to address the NTSB recommendations and to provide increased safety in areas where a pipeline rupture would have a significant impact on the public or the environment. PHMSA does not propose to repeal 49 CFR 192.619(c) for segments located outside of HCAs or MCAs where the routine presence of persons is not expected.

The Engineering Critical Assessment process requires the conservative analysis of: Any in-service cracks, crack-like defects remaining in the pipe, or the largest possible crack that could remain in the pipe, including crack dimensions (length and depth) to determine the predicted failure pressure (PFP) of each defect; failure mode (ductile, brittle, or both) for the microstructure, location, type of defect, and operating conditions (which includes pressure cycling); and failure stress and crack growth analysis to determine the remaining life of the pipeline. An Engineering Critical Assessment must use techniques and procedures developed and confirmed through research findings provided by PHMSA, and other reputable technical sources for longitudinal seam and crack growth such as PHMSA's Comprehensive Study to Understand Longitudinal ERW Seam Research & Development study task reports: Battelle Final Reports (''Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications''—Task 1.4), Report No. 13–002 (''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams''—Subtask 2.4), Report No. 13–021 (''Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue''—Subtask 2.5), and ''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1''—Task 4.5), which can be found on the internet at: *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.*

Section 23 requires pipeline operators to conduct a records verification for pipelines located in certain areas to ensure that the records accurately reflect the physical and operational characteristics of the pipelines and confirm the established MAOP. Congress further directed DOT to require the owner or operator to reconfirm a maximum allowable operating pressure for pipelines with insufficient records. This rule proposes methods for satisfying this direction from Congress. In analyzing the impact of the proposed methods, PHMSA determined that they would result in large cost savings ($2.67 billion over 15 years discounted at 7%, $3.67 billion discounted at 3%) relative to current regulatory requirements for pipelines with insufficient records in 49 CFR 192.107(b), The results of that action indicated that problems similar to those that contributed to the San Bruno incidents are more widespread than previously believed. As a result, the proposed rule would establish consistent standards by which operators would correct these issues in a way that is more cost effective than the current regulations would require (which could require more extensive destructive testing, pressure testing, and/or pipe replacement). PHMSA did not identify any significant adverse safety impacts from allowing operators to use the proposed methods instead of those in the current regulations. See section 4.1.2.3 in the regulatory impact analysis for the analysis of the cost savings.

PHMSA estimated the cost savings to operators associated with the Section 23(c) mileage. Existing regulatory requirements [§ 192.107(b)] related to bad or missing records would be more costly for operators to achieve compliance. Under existing regulations, in order for pipelines with insufficient records to maintain operating pressure, operators must excavate the pipeline at every 10 lengths of pipe (commonly referred to as joints) in accordance with section II–D of appendix B of part 192 (as specified in § 192.107(b)), do a cutout, determine material properties by destructive tensile test, and repair the pipe. The process is similar to doing a repair via pipe replacement. PHMSA developed a blended average for performing such a cutout material verification ($75,000) by reviewing typical costs to repair a small segment of pipe by pipe replacement. The blended average accounted for various pipe diameters and regional cost variance. PHMSA assumed each joint is 40 feet long; ten joints is 400 ft. The number of cutouts required by existing rules is therefore the miles subject to this requirement multiplied by 5,280/400.

The proposed rule would allow operators to perform a sampling program that opportunistically takes advantage of repairs and replacement projects to verify material properties at the same time. Over time, operators will collect enough information gain significant confidence in the material properties of pipe subject to this requirement. The proposed rule nominally targets conducting an average of one material documentation process per mile. In addition, operators would be allowed to perform nondestructive examinations, in lieu of cutouts and destructive testing, when the technology provides a demonstrable level of confidence in the result. PHMSA estimated that the incremental unit cost of adding material documentation activities to a repair or replacement activity would be approximately $17,000 per instance.

The proposed methods for addressing pipelines with insufficient records are exclusively applicable to HCA and all Class 3 and 4 locations. Therefore, if the proposed rule were in effect, operators would be able to use the new methods for addressing pipeline with insufficient records in HCA and all Class 3 and 4 locations, but they would be required to comply with existing (more expensive) requirements for addressing the same issue for pipelines located outside HCA and all Class 3 and 4 locations. Locations outside HCAs and all Class 3 and 4 are by definition lower risk, meaning if incidents occur, the consequences are expected to be smaller than HCA and all Class 3 and 4 locations. PHMSA is considering including provisions in the final rule that would enable operators to use the proposed methods for addressing pipelines with insufficient records in locations outside HCAs and all Class 3 and 4. To maintain flexibility, the proposed methods may be an option to existing requirements—as opposed to a replacement of those requirements. PHMSA requests comments on the impacts of allowing operators to use the new methods for addressing insufficient records beyond HCAs and all Class 3 and 4 locations. What safety risks, if any, should PHMSA consider? What are the potential cost savings?

§ 192.710 Pipeline assessments.

Currently, part 192 does not contain any requirement for operators to conduct integrity assessments of onshore transmission pipelines that are not HCA segments as defined in § 192.903 and therefore not subject to subpart O; *i.e.,* pipelines that are not located in a high consequence area (HCA). Currently, only approximately 7% of onshore gas transmission pipelines are located in HCAs. However, coincident with integrity assessments of HCA segments, industry has, as a practical matter, assessed substantial amounts of pipeline in non-HCA

segments. For example, INGAA noted (see Topic A comments, above) that approximately 90 percent of Class 3 and 4 mileage not in HCAs are presently assessed through over-testing during IM assessments. This is due, in large part, because ILI or pressure testing, by their nature, assess large continuous segments that may contain some HCA segments but that could also contain significant amounts of non- HCA segments. In addition, based on the integrity management principle of continuous improvement, INGAA members have committed (via its IMCI action plan discussed under Topic A, above) to first extend some degree of integrity management to approximately 90 percent of people who live, work or otherwise congregate near pipelines (that is, within the pipelines' Potential Impact Radius, or PIR) by 2012. By 2020, INGAA operators have committed to perform full integrity management on pipelines covering 90 percent of the PIR population. At a minimum, all ASME/ANSI B31.8S requirements will be applied, including mitigating corrosion anomalies and applying integrity management principles. Continuing to areas of less population density, INGAA members plan to apply integrity management principles to pipelines covering 100 percent of the PIR population by 2030.

Given this level of commitment, PHMSA has determined that it is appropriate to codify requirements that additional gas transmission pipelines have an integrity assessment on a periodic basis to monitor for, detect, and remediate deleterious pipeline defects and injurious anomalies. However, INGAA does not represent all pipeline operators subject to part 192. In addition, in order to achieve the desired outcome of performing assessments in areas where people live, work, or congregate, while minimizing the cost of identifying such locations, PHMSA proposes to base the requirements for identifying those locations on processes already being implemented by pipeline operators.

The proposed rule would add a new § 192.710 to require that pipeline segments in moderate consequence areas that can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'') be assessed within 15 years and every 20 years thereafter. PHMSA proposes to define a new term ''moderate consequence area'' or MCA. The definition is based on the same methodology as ''high consequence areas'' as specified in § 192.903, but with less stringent criteria. Moderate consequence areas will be used to define the subset of locations where integrity assessments are required. This approach is proposed as a means to minimize the effort needed on the part of operators to identify the MCAs, since transmission operators must have already performed the analysis in order to have identified the HCAs, or verify that they have no HCAs. In addition, the MCA definition would include locations where interstate highways, freeways, and expressways, and other principal 4-lane arterial roadways are located within the PIR.

Because significant non-HCA pipeline mileage has been previously assessed in conjunction with an assessment of HCA segments in the same pipeline, PHMSA also proposes to allow the use of those prior assessments for non-HCA segments to comply with the new § 192.710, provided that the assessment was conducted in conjunction with an integrity assessment required by subpart O.

The proposed rule would also require that the assessment required by new § 192.710 be conducted using the same methods as proposed for HCAs (see § 192.921, below).

§ 192.711 Transmission lines: General requirements for repair procedures.

Section 192.711 prescribes general requirements for repair procedures. For non-HCA segments, the existing rule requires that permanent repairs be made as soon as feasible. However, no specific repair criteria are provided and no specific timeframe or pressure reduction requirements are provided. PHMSA has determined that more specific repair criteria are needed for pipelines not covered under the integrity management rule. The proposed rule would amend paragraph (b)(1) of section 192.711 to require that specific conditions (*i.e.,* repair criteria) defined in proposed § 192.713 (see below) be remediated, and to require a reduction of operating pressure for conditions that present an immediate hazard.

§ 192.713 Transmission lines: Permanent field repair of imperfections and damages.

Section 192.713 prescribes requirements for the permanent repair of pipeline imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS. PHMSA has determined that more explicit requirements are needed to better identify criteria for the severity of imperfection or damage that must be repaired, and to identify the timeframe within which repairs must be made. Further, PHMSA has determined that such repair criteria should apply to any transmission pipeline not covered under subpart O, Integrity Management regulations. PHMSA believes that establishing these non-HCA segment repair conditions are important because, even though they are not within the defined high consequence locations, they could be located in populated areas and are not without consequence. For example, as reported by operators in the 2011 annual reports, while there are approximately 20,000 miles of gas transmission pipe in HCA segments, there are approximately 65,000 miles of pipe in Class 2, 3, and 4 populated areas. PHMSA believes it is prudent and appropriate to include criteria to assure the timely repair of injurious pipeline defects in non-HCA segments. These changes will ensure the prompt remediation of anomalous conditions, while allowing operators to allocate their resources to high consequence areas on a higher priority basis. The proposed rule would amend § 192.713 to establish immediate, two-year, and monitored conditions which the operator must remediate or monitor to assure pipeline safety. PHMSA proposes to use the same criteria as proposed for HCAs (see 192.933, below), except that conditions for which a one-year response is required in HCAs would require a two-year response in non-HCA segments. In addition, PHMSA proposes to prescribe more explicit requirements for *in situ* evaluation of cracks and crack-like defects using in-the-ditch tools whenever required, such as when an ILI, SCCDA, pressure test failure, or other assessment identifies anomalies that suggest the presence of such defects.

§ 192.750 Launcher and receiver safety.

PHMSA has determined that more explicit requirements are needed for safety when performing maintenance activities that utilize launchers and receivers to insert and remove maintenance tools and devices. Such facilities are subjected to pipeline system pressures. Current regulations for hazardous liquid pipelines (part 195) have, since 1981, contained such safety requirements for scraper and sphere facilities (re: § 195.426). However, current regulations for gas pipelines (part 192) do not similarly require controls or instrumentation to protect against inadvertent breach of system integrity due to incorrect operation of launchers and receivers for in-line inspection tools, scraper, and sphere facilities. Accordingly, the proposed rule would add a new section § 192.750 to require a suitable means to relieve pressure in the barrel and either a means to indicate the pressure in the

barrel or a means to prevent opening if pressure has not been relieved.

§ 192.911 What are the elements of an integrity management program?

Paragraph (k) of § 192.911 requires that integrity management programs include a management of change process as outlined in ASME/ANSI B31.8S, section 11. PHMSA has determined that specific attributes and features of the management of change process as currently specified in ASME/ANSI B31.8S, section 11, should be codified directly within the text of § 192.911(k). The proposed rule would amend paragraph (k) to specify that the features of the operator's management of change process must include the reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. These general attributes of change management are already required by virtue of being invoked by reference to ASME/ANSI B31.8S. However, PHMSA believes it will improve the visibility and emphasis on these important program elements to require them directly in the rule text.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

Section 192.917 requires that integrity management programs for covered pipeline segments identify potential threats to pipeline integrity and use the threat identification in its integrity program. Included within this performance-based process are requirements to identify threats to which the pipeline is susceptible, collect data for analysis, and perform a risk assessment. Special requirements are included to address plastic pipe and particular threats such as third party damage and manufacturing and construction defects. Following the San Bruno accident, the NTSB recommended that Pacific Gas and Electric (PG&E) assess every aspect of its integrity management program, paying particular attention to the areas identified in the investigation, and implement a revised program that includes, at a minimum,

(1) a revised risk model to reflect the Pacific Gas and Electric Company's actual recent experience data on leaks, failures, and incidents;

(2) consideration of all defect and leak data for the life of each pipeline, including its construction, in risk analysis for similar or related segments to ensure that all applicable threats are adequately addressed;

(3) a revised risk analysis methodology to ensure that assessment methods are selected for each pipeline segment that address all applicable integrity threats, with particular emphasis on design/material and construction threats; and

(4) an improved self-assessment that adequately measures whether the program is effectively assessing and evaluating the integrity of each covered pipeline segment (NTSB recommendation P–11–29).

In addition, the NTSB recommended that PG&E conduct threat assessments using the revised risk analysis methodology incorporated in its integrity management program, as recommended in Safety Recommendation P–11–29, and report the results of those assessments to the California Public Utilities Commission and the Pipeline and Hazardous Materials Safety Administration (NTSB recommendation P–11–30). PHMSA has also analyzed the issues the NTSB identified in the investigation related to information analysis and risk assessment. PHMSA held a workshop on July 21, 2011 to address perceived shortcomings in the implementation of integrity management risk assessment processes and the information and data analysis (including records) upon which such risk assessments are based. PHMSA sought input from stakeholders on these issues and has determined that additional clarification and specificity is needed for existing performance-based rules. These clarifications define and emphasize the specific functions that are required for risk assessment and effective risk management.

These aspects of integrity management have been an integral part of PHMSA's expectations for integrity management since the inception of the program. As specified in § 192.907(a), PHMSA expected operators to start with a framework, which would evolve into a more detailed and comprehensive program, and that the operator must continually improve its integrity management program, as it learned more about the process and about the material condition of its pipelines through integrity assessments.

PHMSA elaborated on this philosophy in the notice of final rulemaking for subpart O (68 FR 69778):

The intent of allowing a framework was to acknowledge that an operator cannot develop a complete, fully mature integrity management plan in a year. Nevertheless, it is important that an operator have thought through how the various elements of its plan relate to each other early in the development of its plan. The framework serves this purpose. . . . It need not be fully developed or at the level of detail expected of final integrity management plans. The framework is an initial document that evolves into a more detailed and comprehensive program.

The clarifications and additional specificity proposed in this NPRM (with respect to processes for implementing the threat identification, risk assessment, and preventive and mitigative measures program elements), reflect PHMSA's expectation regarding the degree of progress operators should be making, or should have made, during the first 10 years of the integrity management program.

The current integrity management rule invokes ASME/ANSI B31.8S by reference to require that operators implement specific attributes and features of the threat identification, data analysis, and risk assessment process. PHMSA has determined that those specific attributes and features of the threat identification, data analysis, and risk assessment processes as currently specified in ASME/ANSI B31.8S, section 11, should be codified within the text of § 192.917. While continuing to incorporate the industry standard by reference, the proposed rule would amend § 192.917 to insert certain critical features of the industry standard (ASME/ANSI B31.8S) directly into the body of the Federal regulation. Specifically, PHMSA proposes to specify several pipeline attributes that must be included in pipeline risk assessments and to explicitly require that operators integrate analyzed information, and ensure that data be verified and validated to the maximum extent practical. PHMSA also acknowledges that objective, documented data is not always available or obtainable. To the degree that subjective data from subject matter experts must be used, PHMSA proposes to require that an operator's program include specific features to compensate for subject matter expert bias.

In addition, PHMSA proposes to clarify the performance-based risk assessment aspects of the IM rule to specify that operators perform risk assessments that are adequate to evaluate the effects of interacting threats; determine additional preventive and mitigative measures needed, analyze how a potential failure could affect high consequence areas, including the consequences of the entire worst-case incident scenario from initial failure to incident termination; identify the contribution to risk of each risk factor, or each unique combination of risk factors that interact or simultaneously contribute to risk at a common location, account for, and compensate for, uncertainties in the

model and the data used in the risk assessment; and evaluate risk reduction associated with candidate risk reduction activities such as preventive and mitigative measures. In addition, in response to specific NTSB recommendation P–11–18, PHMSA proposes performance-based language to require that operators validate their risk models in light of incident, leak, and failure history and other historical information. Such features are currently requirements by virtue of being invoked by reference in ASME/ANSI B31.8S. However, PHMSA believes that these important aspects of integrity management will receive greater emphasis and awareness if incorporated directly into the rule text. The proposed rule would also amend the requirements for plastic pipe to provide specific examples of integrity threats for plastic pipe that must be addressed.

Lastly, PHMSA proposes to revise the criteria in § 192.917(e)(3) and (4) for addressing the threat of manufacturing and construction defects and concluding that latent defects are stable as recommended in NTSB recommendation P–11–15.

§ 192.921 How is the baseline assessment to be conducted?

Section 192.921 requires that pipelines subject to integrity management rules have an integrity assessment. Current rules allow the use of in-line inspection, pressure testing in accordance with subpart J, direct assessment for the threats of external corrosion, internal corrosion, and stress corrosion cracking, and other technology that the operator demonstrates provides an equivalent level of understanding of the condition of the pipeline. Following the San Bruno accident, PHMSA has determined that baseline assessment methods should be clarified to emphasize in-line inspection and pressure testing over direct assessment. At San Bruno, PG&E relied heavily on direct assessment under circumstances for which direct assessment was not effective. Further, ongoing research and industry response to the ANPRM is beginning to indicate that stress corrosion cracking direct assessment is not as effective, and does not provide an equivalent understanding of pipe conditions with respect to SCC defects, as ILI or hydrostatic pressure testing at test pressures that exceed those test pressures required by subpart J (*i.e.,* ''spike'' hydrostatic pressure test). Therefore, the proposed rule would require that direct assessment only be allowed when the pipeline cannot be assessed using in-line inspection tools. The proposed rule would also add three additional assessment methods: (1) A ''spike'' hydrostatic pressure test, which is particularly well suited to address SCC and other cracking or crack-like defects, (2) guided wave ultrasonic testing (GWUT) which is particularly appropriate in cases where short segments, such as road or railroad crossing, are difficult to assess, and (3) excavation with direct *in situ* examination.

The current rule merely indicates that in-line inspection (ILI) is an accepted assessment method. The regulations are currently silent on a number of issues that significantly impact the quality and effectiveness of ILI assessment results. Such considerations are described in ASME/ANSI B31.8S, but limited guidance is provided. As discussed above, the proposed rule strengthens guidance in this area by adding a new § 192.493 to require compliance with the requirements and recommendations of API STD 1163–2005, NACE SP0102–2010, and ANSI/ASNT ILI–PQ–2010 when conducting in-line inspection of pipelines. Section 192.921(a)(1) would be revised to require compliance with § 192.493 instead of ASME B31.8S for baseline ILI assessments for covered segments. In addition, a person qualified by knowledge, training, and experience would be required to analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline, and must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

GWUT has been in use by pipeline operators for several years. Previously, operators were required by § 192.921(a)(4) to submit a notification to PHMSA as an ''other technology'' assessment method, in order to use GWUT. In 2007, PHMSA developed guidelines for how it would evaluate notifications for use of GWUT. These guidelines have been effectively used for seven years, and PHMSA has gained confidence that GWUT can be effectively used to assess the integrity of short segments of pipe. PHMSA proposes to incorporate these guidelines into a new Appendix F, which would be invoked in § 192.921. Therefore, notification for use of GWUT would no longer be required.

ASME B31.8S, Section 6.1, describes both excavation and direct *in situ* examination as specialized integrity assessment methods, applicable to particular circumstances:

> *It is important to note that some of the integrity assessment methods discussed in para. 6 only provide indications of defects. Examination using visual inspection and a variety of nondestructive examination (NDE) techniques are required, followed by evaluation of these inspection results in order to characterize the defect. The operator may choose to go directly to examination and evaluation for the entire length of the pipeline segment being assessed, in lieu of conducting inspections. For example, the operator may wish to conduct visual examination of aboveground piping for the external corrosion threat. Since the pipe is accessible for this technique and external corrosion can be readily evaluated, performing in-line inspection is not necessary.*

PHMSA proposes to clarify its requirements to explicitly add excavation and direct *in situ* examination as acceptable assessment methods.

PHMSA also proposes that mandatory integrity assessments proposed for non-HCA segments (see § 192.710, above) could also use these assessment methods.

§ 192.923 How is direct assessment used and for what threats?

As discussed in the changes to §§ 192.927 and 192.929 below, the proposed rule would incorporate by reference NACE SP0206–2006, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas,'' for addressing ICDA and NACE SP0204–2008, ''Stress Corrosion Cracking Direct Assessment,'' for addressing SCCDA. Sections 192.923(b)(2) and (b)(3) would be revised to require compliance with these standards.

§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

Internal corrosion (IC) is a degradation mechanism in which steel pipe loses wall thickness due to corrosion initiating on the inside surface of the pipe. IC is one of several threats that can impact pipeline integrity. IM regulations in 49 CFR part 192 require that pipeline operators assess covered pipe segments periodically to detect degradation from threats that their analyses have indicated could affect the segment. Not all covered segments are subject to an IC threat, but some are. IC direct assessment (ICDA) is an assessment technique that can be used to address this threat for gas pipelines. ICDA involves evaluation and analysis to determine locations at which a

corrosive environment is likely to exist inside a pipeline followed by excavation and direct examination of the pipe wall to determine whether IC is occurring.

Section 192.927 specifies requirements for gas transmission pipeline operators who use ICDA for IM assessments. The requirements in § 192.927 were promulgated before the NACE standard was published. They require that operators follow ASME/ANSI B31.8S provisions related to ICDA. PHMSA has reviewed the NACE standard and finds that it is more comprehensive and rigorous than either § 192.927 or ASME B31.8S in many respects. Some of the most important features in the NACE standard are:

- The NACE standard requires more direct examinations in most cases.
- The NACE standard encompasses the entire pipeline segment and requires that all inputs and outputs be evaluated.
- The NACE standard indirect inspection model is different than the Gas Technology Institute (GTI) model currently referenced in § 192.927, but is considered to be equivalent or superior. Its range of applicability with respect to operating pressure is greater than the GTI model, thus allowing use of ICDA in pipelines with lower operating pressures and higher flow velocities.
- The NACE standard provides additional guidance on how to effectively determine areas to excavate for detailed examinations for internal corrosion.

The existing requirements in § 192.927 have one particular aspect that has proven problematic. The definition of regions and requirements for selection of direct examination locations in the regulations are tied to the covered segment. Covered segment boundaries are determined by population density and other consequence factors without regard to the orientation of the pipe and the presence of locations at which corrosive agents may be introduced or may collect and where internal corrosion would most likely be detected (*e.g.,* low spots). Section 192.927 requires that locations selected for excavation and detailed examination be within covered segments, meaning that the locations at which IC would most likely be detected may not be examined. Thus, the existing requirements do not always facilitate the discovery of internal corrosion that could affect covered segments. PHMSA is proposing to address this problem by incorporating NACE SP0206–2006 and by establishing additional requirements for addressing covered segments within the technical process defined by NACE SP0206–2006.

This proposed rule would require that operators perform two direct examinations within each covered segment the first time ICDA is performed. These examinations are in addition to those required to comply with the NACE standard practice. The additional examinations are consistent with the current requirement in § 192.927(c)(5)(ii) that operators apply more restrictive criteria when conducting ICDA for the first time and are intended to provide a verification, within the HCA, that the results of applying the NACE process for the ICDA are acceptable. Applying the NACE process requires a more precise knowledge of the pipeline's orientation (particularly slope) than operators may have in many cases. Conducting examinations within the HCA during the first application of ICDA will verify that application of the ICDA process provides adequate information about the covered segment. Operators who identify IC on these additional examinations, even though excavations at locations determined using the NACE process did not identify any, will know that improvements to their knowledge of pipeline orientation or other adjustments to their application of the NACE process to the covered segment will be needed for future uses of ICDA. § 192.927(b) and (c) are revised to address these issues.

§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

Stress corrosion cracking (SCC) is a degradation mechanism in which steel pipe develops tight cracks through the combined action of corrosion and tensile stress (residual or applied). These cracks can grow or coalesce to affect the integrity of the pipeline. SCC is one of several threats that can impact pipeline integrity. IM regulations in 49 CFR part 192 require that pipeline operators assess covered pipe segments periodically to detect degradation from threats that their analyses have indicated could affect the segment, though not all covered segments are subject to an SCC threat. SCC direct assessment (SCCDA) is an assessment technique that can be used to address this threat.

Section 192.929 specifies requirements for gas transmission pipeline operators who use SCCDA for IM assessments. The requirements in § 192.929 were promulgated before NACE Standard Practice SP0204–2008 was published. They require that operators follow Appendix A3 of ASME/ANSI B31.8S. This appendix provides some guidance for conducting SCCDA, but is limited to SCC that occurs in high-pH environments. Experience has shown that pipelines also can experience SCC degradation in areas where the surrounding soil has a pH near neutral (referred to as near-neutral SCC). NACE Standard Practice SP0204–2008 addresses near-neutral SCC in addition to high-pH SCC. In addition, the NACE Standard provides technical guidelines and process requirements which are both more comprehensive and rigorous for conducting SCCDA than do § 192.929 or ASME/ANSI B31.8S.

The NACE standard provides additional guidance on:

- The factors that are important in the formation of SCC on a pipeline and what data should be collected;
- Additional factors, such as existing corrosion, which could cause SCC to form;
- Comprehensive data collection guidelines, including the relative importance of each type of data;
- Requirements to conduct close interval surveys of cathodic protection or other above-ground surveys to supplement the data collected during pre-assessment;
- Ranking factors to consider for selecting excavation locations for both near neutral and high pH SCC;
- Requirements on conducting direct examinations, including procedures for collecting environmental data, preparing the pipe surface for examination, and conducting Magnetic Particle Inspection (MPI) examinations of the pipe; and
- Post assessment analysis of results to determine SCCDA effectiveness and assure continual improvement.

NACE SP0204–2008 provides comprehensive guidelines on conducting SCCDA which are commensurate with the state of the art. It is more comprehensive in scope than Appendix A3 of ASME/ANSI B31.8S. PHMSA has concluded the quality and consistency of SCCDA conducted under IM requirements would be improved by requiring the use of NACE SP0204–2008. Revisions to § 192.929 are proposed to address these issues.

§ 192.933 What actions must be taken to address integrity issues?

Section 192.933 specifies those injurious anomalies and defects which must be remediated, and the timeframe within which remediation must occur. PHMSA has determined that the existing rule has gaps, some injurious anomalies and defects are not identified in the rule as requiring remediation in a timely manner commensurate with their seriousness. The proposed rule would designate the following types of anomalies/defects as immediate

conditions: Metal loss greater than 80% of nominal wall thickness; indication of metal-loss affecting certain longitudinal seams; significant stress corrosion cracking; and selective seam weld corrosion. The proposed rule would also designate the following types of anomalies/defects as one-year conditions: Calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations (comparable to the alternative design factor specified in § 192.620(a)); area of general corrosion with a predicted metal loss greater than 50% of nominal wall; predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld; gouge or groove greater than 12.5% of nominal wall; and any indication of crack or crack-like defect other than an immediate condition.

The methods specified in the IM rule to calculate predicted failure pressure are explicitly not valid if metal exceeds 80% of wall thickness. Corrosion affecting a longitudinal seam, especially associated with seam types that are known to be susceptible to latent manufacturing defects such as the failed pipe at San Bruno, and selective seam weld corrosion, are known time sensitive integrity threats. Stress corrosion cracking is listed in ASME/ANSI B31.8S as an immediate repair condition, which is not reflected in the current IM regulations. PHMSA proposes to add requirements to address these gaps.

With respect to SCC, PHMSA has incorporated repair criteria to address NTSB recommendation P–12–3 that resulted from the investigation of the Marshall, Michigan crude oil accident. From its investigation, the NTSB recommended that PHMSA revise § 195.452 to clearly state (1) when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed; (2) the acceptable methods for performing these engineering assessments, including the assessment of cracks coinciding with corrosion with a safety factor that considers the uncertainties associated with sizing of crack defects; (3) criteria for determining when a probable crack defect in a pipeline segment must be excavated and time limits for completing those excavations; (4) pressure restriction limits for crack defects that are not excavated by the required date; and (5) acceptable methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or stress corrosion cracking as applicable (NTSB recommendation P–12–3). Although the recommendation was focused on part 195, the issue applies to gas pipelines regulated under part 192. PHMSA proposes to allow the use of engineering assessment to evaluate if SCC is significant (and thus categorized as an ''immediate'' condition), or not significant (and thus categorized as a ''one-year'' condition), but that an engineering assessment not be allowed to justify not remediating any known indications of SCC. Further, PHMSA proposes to adopt the definition of significant SCC from NACE SP0204–2008.

The current rule includes no explicit metal loss repair criteria for one-year conditions, other than one immediate condition. The rule does direct operators to use Figure 4 in ASME B31.8S to determine non-immediate metal loss repair criteria. PHMSA proposes to repeal the reference to Figure 4, and explicitly include selected metal loss repair conditions in the one-year criteria. These new criteria are consistent with similar criteria currently invoked in the hazardous liquid integrity management rule at 40 CFR 195.452(h). In addition, PHMSA proposes to incorporate safety factors commensurate with the class location in which the pipeline is located, to include predicted failure pressure less than or equal to 1.25 times MAOP for Class 1 locations, 1.39 times MAOP for Class 2 locations, 1.67 times MAOP for Class 3 locations, and 2.00 times MAOP for Class 4 locations in HCAs. Lastly, in response to the lessons learned from the Marshall, Michigan rupture, PHMSA proposes to include any crack or crack-like defect that does not meet the proposed immediate criteria, as a one year condition.

In addition, as a result of its investigation of the Marshall, Michigan crude oil spill, the NTSB recommended that PHMSA revise § 195.452(h)(2), the ''discovery of condition,'' to require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators notify the Pipeline and Hazardous Materials Safety Administration and provide an expected date when adequate information will become available (NTSB recommendation P–12–4). Although the recommendation was focused on part 195, the issue applies to gas pipelines regulated under part 192. Accordingly, PHMSA proposes to amend paragraph (b) of § 192.933 to require that operators notify PHMSA whenever the operator cannot obtain sufficient information to determine if a condition presents a potential threat to the integrity of the pipeline, within 180 days of completing the assessment.

Lastly, PHMSA proposes to require that pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations would be required to be based on properties determined and documented in accordance with § 192.607.

§ 192.935 What additional preventive and mitigative measures must an operator take?

Section 192.935 requires an operator to take additional measures beyond those already required by part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area (HCA). An operator must conduct a risk analysis to identify the additional measures to protect the high consequence area and improve public safety. As discussed above, PHMSA proposes to amend § 192.917 to clarify the guidance for risk analyses operators use to evaluate and select additional preventive and mitigative measures. In addition, PHMSA has determined that some additional prescriptive preventive and mitigative measures are needed to assure that public safety is enhanced in HCAs and affords greater protections for HCAs. This proposed rule would expand the listing of example preventive and mitigative measures operators must consider, require that seismicity be analyzed to mitigate the threat of outside force damage, and would add specific enhanced measures for managing external corrosion and internal corrosion inside HCAs.

With respect to additional preventive and mitigative measures operators must consider, PHMSA proposes to specify that preventive and mitigative measures include (i) correction of the root causes of past incidents in order to prevent recurrence, (ii) adequate operations and maintenance processes, (iii) adequate resources for successful execution of safety related activities, (iv) additional right-of-way patrols, (v) hydrostatic tests in areas where material has quality issues or lost records, (vi) tests to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantiate MAOP evaluations including material property tests from removed pipe that is

representative of the in-service pipeline, (vii) re-coating of damaged, poorly performing, or disbonded coatings, and (viii) additional depth-of-cover survey at roads, streams and rivers, among others. These example preventive and mitigative measures do not alter the fundamental requirement to identify and implement preventive and mitigative measures, but do provide additional guidance and clarify PHMSA's expectations with this important aspect of integrity management.

Section 29 of the Act requires operators to consider seismicity when evaluating threats. Accordingly, PHMSA proposes to include seismicity of the area in evaluating preventive and mitigative measures with respect to the threat of outside force damage.

With respect to internal corrosion and external corrosion, PHMSA proposes to add new paragraphs (f) and (g) to § 192.935 to specify that an operator must enhance its corrosion control program in HCAs to provide additional protections from the threat of corrosion. More specifically, operators would be required to conduct periodic close-interval surveys, coating surveys, interference surveys, and gas-quality monitoring inside HCAs. The requirements would include specific minimum performance standards for these activities.

Lastly, to conform to the revised definition of ''electrical survey,'' the use of that term in § 192.935 would be replaced with ''indirect assessment'' to accommodate other techniques in addition to close-interval surveys.

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

Section 192.937 requires that operators continue to periodically assess HCA segments and periodically evaluate the integrity of each covered pipeline segment. PHMSA has determined that conforming amendments would be needed to implement, and be consistent with, the changes discussed above for §§ 192.917, 192.921, 192.933, and 192.935. The proposed rule would require that the continual process of evaluation and assessment implement and be consistent with data integration and risk assessment information in order to identify the threats specific to each HCA segment, including interacting threats, and the risk represented by these threats (§ 192.917), selection and use of assessment methods (§ 192.921), decisions about remediation (§ 192.933), and identify additional preventive and mitigative measures (§ 192.935) to avert or reduce threats to acceptable levels.

§ 192.939 What are the required reassessment intervals?

Section 192.939 specifies reassessment intervals for pipelines subject to integrity management requirements. Section 5 of the Act includes a technical correction that clarified that periodic reassessments must occur, at a minimum of once every 7 calendar years, but that the Secretary may extend such deadline for an additional 6 months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension. PHMSA would expect that any justification, at a minimum, would need to demonstrate that the extension does not pose a safety risk. By this rulemaking, PHMSA intends to codify this technical correction. The proposed rule would implement this statutory requirement.

§ 192.941 What is a low stress reassessment?

Section 192.941, among other requirements, specifies that, to address the threat of external corrosion on cathodically protected pipe in a HCA segment, an operator must perform an electrical survey (*i.e.* indirect examination tool/method) at least every 7 years on the HCA segment. PHMSA proposes to make conforming edits to the language of this requirement to accommodate the revised definition of the term ''electrical survey.'' To conform to the revised definition of ''electrical survey,'' the use of that term in § 192.941 would be replaced with ''indirect assessment'' to accommodate other techniques in addition to close-interval surveys.

Appendix A to Part 192—Records Retention Schedule for Transmission Pipelines

As discussed under § 192.13, above, the proposed rule would more clearly articulate the requirements for records preparation and retention for transmission pipelines and to require that records be reliable, traceable, verifiable, and complete. New appendix A to part 192 provides specific requirements and records retention periods.

Appendix D to Part 192—Criteria for Cathodic Protection and Determination of Measurements

Appendix D to part 192 specifies requirements for cathodic protection of steel, cast iron & ductile pipelines. PHMSA has determined that this guidance needs to be updated to incorporate lessons learned since this appendix was first promulgated in 1971. The proposed rule would update appendix D accordingly by eliminating outdated guidance on cathodic protection and interpretation of voltage measurement to better align with current standards.

Appendix E to Part 192—Guidance on Determining High Consequence Areas and on Carrying out Requirements in the Integrity Management Rule

Appendix E to part 192 provides guidance for preventive and mitigative measures for HCA segment subject to subpart O. PHMSA proposes to make conforming edits to the language in this appendix to accommodate the revised definition of the term ''electrical survey.'' To conform to the revised definition of ''electrical survey,'' the use of that term in Appendix E would be replaced with ''indirect assessment'' to accommodate other techniques in addition to close-interval surveys.

Appendix F to Part 192—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

As discussed under § 192.941 above, a new appendix F to part 192 is proposed to provide specific requirements and acceptance criteria for the use of GWUT as an integrity assessment method. Operators must apply all 18 criteria defined in Appendix F to use GWUT as an integrity assessment method. If an operator applied GWUT technology in a manner that does not conform to Appendix F, it would be considered ''other technology'' in §§ 192.710, 192.921, and 192. 937.

VI. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 60 standards and specifications developed and published by standard developing organizations (SDOs). In general, SDOs update and revise their published standards every 3 to 5 years to reflect modern technology and best technical practices.

The National Technology Transfer and Advancement Act of 1995 (Pub. L. 104–113) directs Federal agencies to use voluntary consensus standards in lieu of government-written standards whenever possible. Voluntary consensus standards are standards developed or adopted by voluntary bodies that develop, establish, or coordinate technical standards using agreed-upon procedures. In addition, Office of Management and Budget (OMB) issued OMB Circular A–119 to implement Section 12(d) of Public Law 104–113 relative to the utilization of consensus technical standards by

Federal agencies. This circular provides guidance for agencies participating in voluntary consensus standards bodies and describes procedures for satisfying the reporting requirements in Public Law 104–113.

In accordance with the preceding provisions, PHMSA has the responsibility for determining, via petitions or otherwise, which currently referenced standards should be updated, revised, or removed, and which standards should be added to 49 CFR parts 192, 193, and 195. Revisions to incorporated by reference materials in 49 CFR parts 192, 193, and 195 are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Public Law 112–90. Section 24 states: ''Beginning 1 year after the date of enactment of this subsection, the Secretary may not issue guidance or a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge, on an Internet Web site.'' 49 U.S.C. 60102(p).

On August 9, 2013, Public Law 113–30 revised 49 U.S.C. 60102(p) to replace ''1 year'' with ''3 years'' and remove the phrases ''guidance or'' and '', on an Internet Web site.'' This resulted in the current language in 49 U.S.C. 60102(p), which now reads as follows:

''Beginning 3 years after the date of enactment of this subsection, the Secretary may not issue a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge.''

Further, the Office of the Federal Register issued a November 7, 2014, rulemaking (79 FR 66278) that revised 1 CFR 51.5 to require that agencies detail in the preamble of a proposed rulemaking the ways the materials it proposes to incorporate by reference are reasonably available to interested parties, or how the agency worked to make those materials reasonably available to interested parties. In relation to this proposed rulemaking, PHMSA has contacted each SDO and has requested a hyperlink to a free copy of each standard that has been proposed for incorporation by reference. Access to these standards will be granted until the end of the comment period for this proposed rulemaking. Access to these documents can be found on the PHMSA Web site at the following URL: *http://www.phmsa.dot.gov/pipeline/regs* under ''Standards Incorporated by Reference.''

Consistent with the proposed amendments in this document, PHMSA proposes to incorporate by reference the following materials identified as follows:

• API Standard 1163–2005, ''In-line Inspection Systems Qualification Standards.''—This Standard serves as an umbrella document to be used with and complement companion standards. NACE RP0102 Standard Recommended Practice, In-Line Inspections of Pipelines; and ASNT ILI–PQ In-Line Inspection Personnel Qualification & Certification all have been developed enabling service providers and pipeline operators to provide rigorous processes that will consistently qualify the equipment, people, processes and software utilized in the in-line inspection industry.

• NACE Standard Practice 0102–2010, ''Inline Inspection of Pipelines.''—This standard is intended for use by individuals and teams planning, implementing, and managing ILI projects and programs. The incorporation of this standard into the Federal pipeline safety regulations would promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software utilized by the ILI industry.

• NACE Standard Practice 0204–2008, ''Stress Corrosion Cracking Direct Assessment.''—The standard practice for SCCDA presented in this standard addresses the situation in which a pipeline company has identified a portion of its pipeline as an area of interest with respect to SCC based on its history, operations, and risk assessment process and has decided that direct assessment is an appropriate approach for integrity assessment. This standard provides guidance for managing SCC by selecting potential pipeline segments, selecting dig sites within those segments, inspecting the pipe, collecting and analyzing data during the dig, establishing a mitigation program, defining the reevaluation interval, and evaluating the effectiveness of the SCCDA process.

• NACE Standard Practice 0206–2006, ''International Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas.'' This standard covers the NACE internal corrosion direct assessment (ICDA) process for normally dry natural gas pipeline systems. This standard is intended to serve as a guide for applying the NACE DG–ICDA process on natural gas pipeline systems that meet the feasibility requirements of Paragraph 3.3 of this standard.

• ANSI/ASNT ILI–PQ–2010, ''In-line Inspection Personnel Qualification and Certification.'' The ASNT standard provides for qualification and certification requirements that are not addressed in part 192. The incorporation of this standard into the Federal pipeline safety regulations would promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software utilized by the ILI industry.

• Battelle's Experience with ERW and Flash Welding Seam Failures: Causes and Implications (Task 1.4). This report presents an evaluation of the database dealing with failures originating in electric resistance welds (ERW) and flash weld (FW) seam defects as quantified by Battelle's archives and the related literature.

• Battelle Memorial Institute, ''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams'' (Subtask 2.4). This document presents an analysis of two known defect assessment methods in an effort to find suitable ways to satisfactorily predict the failure stress levels of defects in or adjacent to ERW or flash-welded line pipe seams.

• Battelle Final Report No. 13–021, ''Predicting Times to Failures for ERW Seam Defects that Grow by Pressure Cycle Induced Fatigue (Subtask 2.5).'' The work described in this report is part of a comprehensive study of ERW seam integrity and its impact on pipeline safety. The objective of this part of the work is to identify appropriate means for predicting the remaining lives of defects that remain after a seam integrity assessment and that may become enlarged by pressure-cycle-induced fatigue.

• Battelle Memorial Institute, ''Final Summary Report and recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1'' (Task 4.5).—This report summarizes work completed as part of a comprehensive project that resulted from a contract with Battelle, working with Kiefner and Associates (KAI) and Det Norske Veritas (DNV) as subcontractors, to address the concerns identified in NTSB recommendation (P–09–1) regarding the safety and performance of ERW pipe.

VII. Regulatory Analysis and Notices

This proposed rule is published under the authority of the Federal Pipeline Safety Law (49 U.S.C. 60101 *et seq.*). Section 60102 authorizes the Secretary of Transportation to issue regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. The amendments to the requirements for petroleum gas pipelines addressed in this rulemaking are issued under this authority.

Executive Orders 12866 and 13563, and DOT Policies and Procedures

This proposed rule is a significant regulatory action under section 3(f) of Executive Order 12866 and, therefore, was reviewed by the Office of Management and Budget. This proposed rule is significant under the Regulatory Policies and Procedures of the Department of Transportation.

(44 FR 11034, February 26, 1979).

Executive Orders 12866 and 13563 require that proposed rules deemed ''significant'' include a Regulatory Impact Analysis, and that this analysis requires quantified estimates of the benefits and costs of the rule. PHMSA is providing the PRIA for this proposed rule simultaneously with this document, and it is available in the docket.

PHMSA estimates the total present value of benefits from the proposed rule to be approximately $3,234 to $3,738 million [39] using a 7% discount rate ($4,050 to $4,663 million using a 3% discount rate) and the present value of costs to be approximately $597 million using a 7% discount rate ($711 million using a 3% discount rate). The table in the executive summary provides a detailed estimate of the average annual costs and benefits for each major topic area.

Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Flexibility Fairness Act of 1996, requires Federal regulatory agencies to prepare an Initial Regulatory Flexibility Analysis (IFRA) for any proposed rule subject to notice-and-comment rulemaking under the Administrative Procedure Act unless the agency head certifies that the making will not have a significant economic impact on a substantial number of small entities. PHMSA has data on gas transmission pipeline operators affected by the proposed rule. However, PHMSA does not have data on currently unregulated gas gathering pipeline operators. Therefore, PHMSA prepared an IFRA which is available in the docket for the rulemaking.

[39] Range reflects uncertainty in defect failure rates for Topic Area 1.

Executive Order 13175

PHMSA has analyzed this proposed rule according to the principles and criteria in Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments.'' Because this proposed rule would not significantly or uniquely affect the communities of the Indian tribal governments or impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. PHMSA estimates that the proposals in this rulemaking will impact the information collections described below.

Based on the proposals in this rule, PHMSA will submit an information collection revision request to OMB for approval based on the requirements in this proposed rule. The information collection is contained in the pipeline safety regulations, 49 CFR parts 190 through 199. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection. The information collection burden for the following information collections are estimated to be revised as follows:

1. *Title:* Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 04/30/2018.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation at the Secretary's request. Based on the proposed revisions in this rule, PHMSA estimates that 100 new Type A, Area 2 gas gathering pipeline operators ~ (2200 Type A, Area 2 miles w/o prior regulation/22) will be new to these requirements. PHMSA estimates that it will take these 100 operators 6 hours to create and maintain records associated with Emergency Planning requirements. Therefore, PHMSA expects to add 100 responses and 600 hours to this information collection as a result of the provisions in the proposed rule.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 12,400.

Total Annual Burden Hours: 941,054.

Frequency of Collection: On occasion.

2. *Title:* Reporting Safety-Related Conditions on Gas, Hazardous Liquid, and Carbon Dioxide Pipelines and Liquefied Natural Gas Facilities.

OMB Control Number: 2137–0578.

Current Expiration Date: 7/31/2017.

Abstract: 49 U.S.C. 60102 requires each operator of a pipeline facility (except master meter operators) to submit to DOT a written report on any safety-related condition that causes or has caused a significant change or restriction in the operation of a pipeline facility or a condition that is a hazards to life, property or the environment. Based on the proposed revisions in this rule, PHMSA estimates that an additional 71,109 miles of pipe will become subject to the safety related condition reporting requirements. PHMSA estimates that such reports will be submitted at a rate of 0.23 reports per 1,000 miles. PHMSA expects that, collectively, Type A, Area 2 lines will submit approximately 16 reports on an annual basis. As a result, PHMSA is adding an additional 16 responses and 96 burden hours to this information collection.

Affected Public: Operators of Natural Gas, Hazardous Liquid, and Liquefied Natural Gas pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 158.

Total Annual Burden Hours: 948.

Frequency of Collection: On occasion.

3. *Title:* Pipeline Integrity Management in High Consequence Areas Gas Transmission Pipeline Operators.

OMB Control Number: 2137–0610.

Current Expiration Date: 3/31/2016.

Abstract: This information collection request pertains to Gas Transmission operators jurisdictional to 49 CFR part 192 subpart O—Gas Transmission Integrity Management Program. PHMSA is proposing that operators subject to Integrity Management requirements provide PHMSA notice when 180 days is insufficient to conduct an integrity assessment following the discovery of a condition (192.933). PHMSA estimates that 20% of the 721 operators (721*.2 =

144 operators) will file such a notification. PHMSA estimates that each notification will take about 30 minutes. Based on this provision, PHMSA proposes to add 144 responses and 72 hours to this information collection.

Affected Public: Gas Transmission operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 877.

Total Annual Burden Hours: 1,018,879.

Frequency of Collection: On occasion.

4. *Title:* Incident and Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: 10/31/2017.

Abstract: This information collection covers the collection of information from Gas pipeline operators for Incidents and Annual reports. PHMSA is revising the Gas Transmission Incident report to incorporate Moderate Consequence Areas and to address Gathering line operators that are only subject to reporting. PHMSA estimates that operators of currently exempt gas gathering pipelines will have to submit incident reports for 27.5 incidents over the next three years, an average of 9 reports annually. However, the proposed rule is expected to reduce the number of incidents by at least 10 each year which would result in a cumulative increase of zero incidents.

PHMSA is also revising the Gas Transmission and Gas Gathering Annual Report to collect additional information including mileage of pipe subject to the IVP and MCA criteria. Based on the proposed revisions, PHMSA estimates that an additional annual 500 reports to the current 1,440 reports will be submitted based on the required reporting of non-regulated gathering lines and gathering lines now subject to certain safety provisions. Further PHMSA estimates that the Annual report will require an additional 5 hours/report to the currently approved 42 hours due to collection of MCA data and IVP provisions. Therefore the overall burden allotted for the reporting of Gas annual reports will increase by 30,700 hours from 60,480 hours (42 hours*1,440 reports) to 91,180 hours (47 hours*1,940 reports).

As a result of the provisions mentioned above, the burden for this information collection will increase by 500 responses and 30,700 burden hours.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 12,664.

Total Annual Burden Hours: 103,182

Frequency of Collection: On occasion.

5. *Title:* National Registry of Pipeline and LNG Operators.

OMB Control Number: 2137–0627.

Current Expiration Date: 05/31/2018.

Abstract: The National Registry of Pipeline and LNG Operators serves as the storehouse for the reporting requirements for an operator regulated or subject to reporting requirements under 49 CFR part 192, 193, or 195. This registry incorporates the use of two forms. The forms for assigning and maintaining Operator Identification (OPID) information are the Operator Assignment Request Form (PHMSA F 1000.1) and Operator Registry Notification Form (PHMSA F 1000.2). PHMSA plans to make revisions to the form/instructions to account for ''reporting only'' gathering operators. PHMSA estimates that 500 gas gathering operators will require a new OPID. Based on a 3 year average this results in an additional 167 responses a year initially. In addition to the OPID assignment, PHMSA estimates that 123 gathering operators will submit approx. 1 notification per year. PHMSA estimates that each submission will take approx. 1 hour to complete. Based on these provisions, PHMSA expects this information collection to increase by 290 responses and 290 burden hours.

Affected Public: Operators of Natural Gas, Hazardous Liquid, and Liquefied Natural Gas pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 920.

Total Annual Burden Hours: 920.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Dow or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue SE., Washington, DC 20590–0001, Telephone (202) 366–4595.

Comments are invited on:

(a) The need for the proposed collection of information for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burden of the revised collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques.

Send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street NW., Washington, DC 20503. Comments should be submitted on or prior to June 7, 2016.

Unfunded Mandates Reform Act of 1995

An evaluation of Unfunded Mandates Reform Act (UMRA) considerations is performed as part of the Preliminary Regulatory Impact Assessment. The estimated costs to the States are approximately $1.3 million per year and are significantly less than the UMRA criterion of $151 million per year ($100 million, adjusted for inflation). The estimated costs to the private sector are in excess of the UMRA criterion of $151 million per year. A copy of the Preliminary Regulatory Impact Assessment is available for review in the docket.

National Environmental Policy Act

PHMSA analyzed this proposed rule in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. 4332), the Council on Environmental Quality regulations (40 CFR 1500–1508), and DOT Order 5610.1C, and has preliminarily determined this action will not significantly affect the quality of the human environment. The Environmental Assessment for this proposed action is in the docket.

Executive Order 13132

PHMSA has analyzed this proposed rule according to Executive Order 13132 (''Federalism''). The proposed rule does not have a substantial direct effect on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government. This proposed rule does not impose substantial direct compliance costs on State and local governments. This proposed rule would not preempt state law for intrastate pipelines. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

Executive Order 13211

This proposed rule is not a ''significant energy action'' under Executive Order 13211 (Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use). It is not likely to have a significant adverse effect on

supply, distribution, or energy use. Further, the Office of Information and Regulatory Affairs has not designated this proposed rule as a significant energy action.

Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (70 FR 19477) or visit *http://dms.dot.gov.*

Regulation Identifier Number (RIN)

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN number contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

List of Subjects

49 CFR Part 191

Pipeline reporting requirements, Integrity Management, Pipeline safety, Gas gathering.

49 CFR Part 192

Incorporation by reference, Pipeline Safety, Fire prevention, Security measures.

In consideration of the foregoing, PHMSA proposes to amend 49 CFR parts 191 and 192 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for part 191 is revised to read as follows:

Authority: 49 U.S.C. 5121, 60102, 60103, 60104, 60108, 60117, 60118, 60124, 60132, and 60139; and 49 CFR 1.97.

■ 2. In § 191.1, paragraphs (a) and (b)(2) and (3) are revised, paragraph (b)(4) is deleted, and paragraph (c) is added to read as follows:

§ 191.1 Scope.

(a) This part prescribes requirements for the reporting of incidents, safety-related conditions, exceedances of maximum allowable operating pressure (MAOP), annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of gas pipeline facilities located in the United States or Puerto Rico, including pipelines within the limits of the Outer Continental Shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331). This part applies to offshore gathering lines and to onshore gathering lines, whether designated as ''regulated onshore gathering lines'' or not (as determined in § 192.8 of this chapter).

(b) * * *

(2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9; or

(3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator.

(c) Sections 191.22(b) and 191.29 do not apply to gathering of gas—

(1) Through a pipeline that operates at less than 0 psig (0 kPa);

(2) Through an onshore pipeline that is not a regulated onshore gathering line (as determined in § 192.8 of this chapter); and

(3) Within inlets of the Gulf of Mexico, except for the requirements in § 192.612.

■ 3. In § 191.23, revise paragraph (a)(5), add paragraph (a)(9), and revise paragraph (b)(4) to read as follows:

§ 191.23 Reporting safety-related conditions.

(a) * * **

(5) Any malfunction or operating error that causes the pressure of a distribution or gathering pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the margin (build-up) allowed for operation of pressure limiting or control devices.

* * * * *

(9) For transmission pipelines, each exceedance of the maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in §§ 192.201, 192.620(e), and 192.739, as applicable.

(b) * * *

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline and any condition under paragraph (a)(9) of this section.

■ 4. Section 191.25 is revised to read as follows:

§ 191.25 Filing safety-related condition reports.

(a) Each report of a safety-related condition under § 191.23(a)(1) through (8) must be filed (received by the Associate Administrator, OPS) within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reports may be transmitted by electronic mail to *InformationResourcesManager@dot.gov* or by facsimile at (202) 366–7128.

(b) Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in § 191.23(a)(9) for a gas transmission pipeline must be reported within five calendar days of the exceedance using the reporting methods and report requirements described in § 191.25(c).

(c) Reports may be filed by emailing information to *InformationResourcesManager@dot.gov.or* by fax to (202) 366–7128. The report must be headed ''Safety-Related Condition Report'' or for § 191.23(a)(9) ''Maximum Allowable Operating Pressure Exceedances'', and provide the following information:

(1) Name, principal address, and operator identification number (OPID) of operator.

(2) Date of report.

(3) Name, job title, and business telephone number of person submitting the report.

(4) Name, job title, and business telephone number of person who determined that the condition exists.

(5) Date condition was discovered and date condition was first determined to exist.

(6) Location of condition, with reference to the State (and town, city, or county) or Offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.

(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the

condition on safety, and the name of the commodity transported or stored.

(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up future corrective action, including the anticipated schedule for starting and concluding such action.

■ 4a. In § 191.29, paragraph (c) is added to read as follows:

§ 191.29 National Pipeline Mapping System.

* * * * *

(c) This section does not apply to gathering lines.

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 5. The authority citation for part 192 is revised to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, 60116, 60118, 60137, and 60139; and 49 CFR 1.97.

■ 6. In § 192.3:

■ a. Add definitions for ''Close interval survey'', ''Distribution center'', and ''Dry gas or dry natural gas'' in alphabetical order;

■ b. Revise the definition of ''Electrical survey'';

■ c. Add definitions for ''Gas processing plant'' and ''Gas treatment facility,'' in alphabetical order;

■ d. Revise the definition of ''Gathering line'';

■ e. Add definitions for ''Hard spot'', ''In-line inspection (ILI)'', ''In-line inspection tool or instrumented internal inspection device'', ''Legacy construction techniques'', ''Legacy pipe'', ''Moderate consequence area'', ''Modern pipe'', ''Occupied site'', ''Onshore production facility/ operation'', ''Significant seam cracking'', ''Significant stress corrosion cracking'', in alphabetical order;

■ f. Revise the definition of ''Transmission line'' and its note; and

■ g. Add a definition for ''Wrinkle bend'' in alphabetical order.

The additions and revisions to read as follows:

§ 192.3 Definitions.

* * * * *

Close interval survey means a series of closely spaced pipe-to-electrolyte potential measurements taken to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary.

* * * * *

Distribution center means a location where gas volumes are either metered or have pressure or volume reductions prior to delivery to customers through a distribution line.

* * * * *

Dry gas or dry natural gas means gas with less than 7 pounds of water per million (MM) cubic feet and not subject to excessive upsets allowing electrolytes into the gas stream.

Electrical survey means a series of closely spaced measurements of the potential difference between two reference electrodes to determine where the current is leaving the pipe on ineffectively coated or bare pipelines.

* * * * *

Gas processing plant means a natural gas processing operation, other than production processing, operated for the purpose of extracting entrained natural gas liquids and other associated non-entrained liquids from the gas stream and does not include a natural gas processing plant located on a transmission line, commonly referred to as a straddle plant.

Gas treatment facility means one or a series of gas treatment operations, operated for the purpose of removing impurities (*e.g.,* water, solids, basic sediment and water, sulfur compounds, carbon dioxide, etc.) that is not associated with a processing plant or compressor station and is not on a transmission line.

Gathering line (Onshore) means a pipeline, or a connected series of pipelines, and equipment used to collect gas from the endpoint of a production facility/operation and transport it to the furthermost point downstream of the endpoints described in paragraphs (1) through (4) of this definition:

(1) The inlet of 1st gas processing plant, unless the operator submits a request for approval to the Associate Administrator of Pipeline Safety that demonstrates, using sound engineering principles, that gathering extends to a further downstream plant other than a plant located on a transmission line and the Associate Administrator of Pipeline Safety approves such request;

(2) The outlet of gas treatment facility that is not associated with a processing plant or compressor station;

(3) Outlet of the furthermost downstream compressor used to facilitate delivery into a pipeline, other than another gathering line; or

(4) The point where separate production fields are commingled, provided the distance between the interconnection of the fields does not exceed 50 miles, unless the Associate Administrator of Pipeline Safety finds a longer separation distance is justified in a particular case (see § 190.9 of this chapter).

(5) Gathering may continue beyond the endpoints described in paragraphs (1) through (4) of this definition to the point gas is delivered into another pipeline, provided that it only does the following:

(i) It delivers gas into another gathering line;

(A) It does not leave the operator's facility surface property (owned or leased, not necessarily the fence line);

(B) It does not leave an adjacent property owned or leased by another pipeline operator's property—where custody transfer takes place; or

(C) It does not exceed a length of one mile, and it does not cross a state or federal highway or an active railroad; or

(ii) It transports gas to production or gathering facilities for use as fuel, gas lift, or gas injection gas.

(6) Pipelines that serve residential, commercial, or industrial customers that originate at a tap on gathering lines are not gathering lines; they are service lines and are commonly referred to as farm taps.

* * * * *

Hard spot means steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinnel 327 HB or Vickers 345 HV10).

* * * * *

In-line inspection (ILI) means the inspection of a pipeline from the interior of the pipe using an in-line inspection tool, which is also called *intelligent* or *smart pigging.*

In-line inspection tool or *instrumented internal inspection device* means a device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside, which is also called an *intelligent* or *smart pig.*

Legacy construction techniques mean usage of any historic, now-abandoned, construction practice to construct or repair pipe segments, including any of the following techniques:

(1) Wrinkle bends;

(2) Miter joints exceeding three degrees;

(3) Dresser couplings;

(4) Non-standard fittings or field fabricated fittings (*e.g.,* orange-peeled reducers) with unknown pressure ratings;

(5) Acetylene welds;

(6) Bell and spigots; or
(7) Puddle welds.

Legacy pipe means steel pipe manufactured using any of the following techniques, regardless of the date of manufacture:

(1) Low-Frequency Electric Resistance Welded (LF–ERW);
(2) Direct-Current Electric Resistance Welded (DC–ERW);
(3) Single Submerged Arc Welded (SSAW);
(4) Electric Flash Welded (EFW);
(5) Wrought iron;
(6) Pipe made from Bessemer steel; or
(7) Any pipe with a longitudinal joint factor, as defined in § 192.113, less than 1.0 (such as lap-welded pipe) or with a type of longitudinal joint that is unknown or cannot be determined, including pipe of unknown manufacturing specification.

* * * * *

Moderate consequence area means an onshore area that is within a potential impact circle, as defined in § 192.903, containing five (5) or more buildings intended for human occupancy, an occupied site, or a right-of-way for a designated interstate, freeway, expressway, and other principal 4-lane arterial roadway as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures,* and does not meet the definition of high consequence area, as defined in § 192.903. The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an occupied site, five (5) or more buildings intended for human occupancy, or a right-of-way for a designated interstate, freeway, expressway, or other principal 4-lane arterial roadway, to the outermost edge of the last contiguous potential impact circle that contains either an occupied site, five (5) or more buildings intended for human occupancy, or a right-of-way for a designated interstate, freeway, expressway, or other principal 4-lane arterial roadway.

Modern pipe means any steel pipe that it is not legacy pipe, regardless of the date of manufacture, and has a longitudinal joint factor of 1.0 as defined in § 192.113. Modern pipe refers to all pipe that is not legacy pipe.

* * * * *

Occupied site means each of the following areas:

(1) An outside area or open structure that is occupied by five (5) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or

(2) A building that is occupied by five (5) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4–H facilities, or roller skating rinks.

* * * * *

Onshore production facility or *onshore production operation* means wellbores, equipment, piping, and associated appurtenances confined to the physical acts of extraction or recovery of gas from the earth and the initial preparation for transportation. Preparation for transportation does not necessarily mean the gas will meet ''pipeline quality'' specifications as may be commonly understood or contained in many contractual agreements. Piping as used in this definition may include individual well flow lines, equipment piping, and transfer lines between production operation equipment components. Production facilities terminate at the furthermost downstream point where: Measurement for the purposes of calculating minerals severance occurs; or there is commingling of the flow stream from two or more wells.

* * * * *

Significant seam cracking means cracks or crack-like flaws in the longitudinal seam or heat affected zone of a seam weld where the deepest crack is greater than or equal to 10% of wall thickness or the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a failure pressure less than or equal to 110% of SMYS, as determined in accordance with fracture mechanics failure pressure evaluation methods (§§ 192.624(c) and (d)) for the failure mode using conservative Charpy energy values of the crack-related conditions.

Significant stress corrosion cracking means a stress corrosion cracking (SCC) cluster in which the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS.

* * * * *

Transmission line means a pipeline, other than a gathering line, that: transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; has an MAOP of 20 percent or more of SMYS; or transports gas within a storage field.

Note: A large volume customer (factories, power plants, and institutional users of gas) may receive similar volumes of gas as a distribution center.

* * * * *

Wrinkle bend. (1) Means a bend in the pipe that was formed in the field during construction such that the inside radius of the bend has one or more ripples with:

(i) An amplitude greater than or equal to 1.5 times the wall thickness of the pipe, measured from peak to valley of the ripple; or

(ii) With ripples less than 1.5 times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under 12.

(2) If the length of the wrinkle bend cannot be reliably determined, then *wrinkle bend* means a bend in the pipe where (h/D)*100 exceeds 2 when S is less than 37,000 psi (255 MPa), where (h/D)*100 exceeds $\left(\frac{47{,}000-S}{10{,}000}+1\right)$ for psi [$\left(\frac{324-S}{69}+1\right)$for MPa] when S is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where (h/D)*100 exceeds 1 when S is 47,000 psi (324 MPa) or more.

D = The outside diameter of the pipe, in. (mm),
h = The crest-to-trough height of the ripple, in. (mm), and
S = The maximum operating hoop stress, psi (S/145, MPa).

■ 7. In § 192.5, paragraph (d) is added to read as follows:

§ 192.5 Class locations.

* * * * *

(d) Records for transmission pipelines documenting class locations and demonstrating how an operator determined class locations in accordance with this section must be retained for the life of the pipeline.

■ 8. Amend § 192.7 by removing and reserving paragraph (b)(4) and adding paragraphs (b)(10), (g)(2) through (4), (k), and (l).

The additions read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

* * * * *

(b) * * *

(10) API STD 1163–2005, ''In-Line Inspection Systems Qualification Standard,'' 1st edition, August 2001, (API STD 1163), IBR approved for § 192.493.

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(g) * * *

(2) NACE Standard Practice 0102–2010, ''Inline Inspection of Pipelines,'' Revised 2010, (NACE SP0102), IBR approved for §§ 192.150(a) and 192.493.

(3) NACE Standard Practice 0204–2008, ''Stress Corrosion Cracking Direct Assessment,'' Revised 2008, (NACE SP0204), Reaffirmed 2008, IBR approved for §§ 192.923(b)(3) and 192.929.

(4) NACE Standard Practice 0206–2006, ''International Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas,'' (NACE SP0206–2006), IBR approved for §§ 192.923(b)(2), 192.927(b), and 192.927(c).

* * * * *

(k) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228, phone (800) 222–2768, *https://www.asnt.org/*.

(1) ANSI/ASNT ILI–PQ–2010, ''In-line Inspection Personnel Qualification and Certification,'' 2010, (ANSI/ASNT ILI–PQ–2010), IBR approved for § 192.493.

(2) [Reserved]

(l) Battelle Memorial Institute, 505 King Avenue, Columbus, OH 43201, phone (800) 201–2011, *http://www.battelle.org/*.

(1) Battelle's Experience with ERW and Flash Welding Seam Failures: Causes and Implications (Task 1.4), IBR approved for § 192.624(c) and (d).

(2) Battelle Memorial Institute, ''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams'' (Subtask 2.4), IBR approved for § 192.624(c) and (d).

(3) Battelle Final Report No. 13–021, ''Predicting Times to Failures for ERW Seam Defects that Grow by Pressure Cycle Induced Fatigue (Subtask 2.5), IBR approved for § 192.624(c) and (d).

(4) Battelle Memorial Institute, ''Final Summary Report and recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1'' (Task 4.5), IBR approved for § 192.624(c) and (d).

■ 9. Section 192.8 is revised to read as follows:

§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

(a) Each operator must determine and maintain records documenting the beginning and endpoints of each gathering line it operates using the definitions of onshore production facility (or onshore production operation), gas processing facility, gas treatment facility, and onshore gathering line as defined in § 192.3 by *[date 6 months after effective date of the final rule]* or before the pipeline is placed into operation, whichever is later.

(b) Each operator must determine and maintain records documenting the beginning and endpoints of each regulated onshore gathering line it operates as determined in § 192.8(c) by *[date 6 months after effective date of the final rule]* or before the pipeline is placed into operation, whichever is later.

(c) For purposes of part 191 of this chapter and § 192.9, ''regulated onshore gathering line'' means:

(1) Each onshore gathering line (or segment of onshore gathering line) with a feature described in the second column that lies in an area described in the third column; and

(2) As applicable, additional lengths of line described in the fourth column to provide a safety buffer:

Type	Feature	Area	Safety buffer
A	—Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is more than 125 psig (862 kPa).	*Area 1.* Class 2, 3, or 4 location (*see* § 192.5). *Area 2.* Class 1 location with a nominal diameter of 8 inches or greater.	None.
B	—Non-metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and thew MAOP is 125 psig (862 kPa) or less.	*Area 1.* Class 3, or 4 location .... *Area 2.* An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location; (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings; or (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings.	If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2(b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.

■ 10. In § 192.9, paragraphs (c), (d), and (e) are revised and paragraph (f) is added to read as follows:

§ 192.9 What requirements apply to gathering lines?

* * * * *

(c) *Type A, Area 1 lines.* An operator of a Type A, Area 1 regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.13, 192.150, 192.319, 192.461(f), 192.465(f), 192.473(c), 192.478, 192.710, 192.713, and in subpart O of this part. However, an operator of a Type A, Area 1 regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) *Type A, Area 2 and Type B lines.* An operator of a Type A, Area 2 or Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines;

(3) Carry out a damage prevention program under § 192.614;

(4) Establish a public education program under § 192.616;

(5) Establish the MAOP of the line under § 192.619;

(6) Install and maintain line markers according to the requirements for transmission lines in § 192.707;

(7) Conduct leakage surveys in accordance with § 192.706 using leak detection equipment and promptly repair hazardous leaks that are discovered in accordance with § 192.703(c); and

(8) For a Type A, Area 2 regulated onshore gathering line only, develop procedures, training, notifications, emergency plans and implement as described in § 192.615.

(e) If a regulated onshore gathering line existing on *[effective date of the final rule]* was not previously subject to this part, an operator has until *[date two years after effective date of the final rule]* to comply with the applicable requirements of this section, unless the Administrator finds a later deadline is justified in a particular case.

(f) If, after *[effective date of the final rule],* a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has one year for Type A, Area 2 and Type B lines and two years for Type A, Area 1 lines after the line becomes a regulated onshore gathering line to comply with this section.

■ 11. In § 192.13, paragraphs (a) and (b) are revised and paragraphs (d) and (e) are added to read as follows:

§ 192.13 What general requirements apply to pipelines regulated under this part?

(a) No person may operate a segment of pipeline listed in the first column that is readied for service after the date in the second column, unless:

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part according to the requirements in § 192.14.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006.	March 15 2007.
Regulated onshore gathering line to which this part did not apply until *[effective date of the final rule]*.	*[date 1 year after effective date of the final rule].*
All other pipelines	March 12, 1971.

(b) No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006.	March 15, 2007.
Regulated onshore gathering line to which this part did not apply until *[effective date of the final rule]*.	*[date 1 year after effective date of the final rule].*
All other pipelines	November 12, 1970.

* * * * *

(d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, risks to the public and environment as an integral part of managing pipeline design, construction, operation, maintenance, and integrity, including management of change. Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. A management of change process must include the following: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff.

(e) Each operator must make and retain records that demonstrate compliance with this part.

(1) Operators of transmission pipelines must keep records for the retention period specified in appendix A to part 192.

(2) Records must be reliable, traceable, verifiable, and complete.

(3) For pipeline material manufactured before *[effective date of the final rule]* and for which records are not available, each operator must re-establish pipeline material documentation in accordance with the requirements of § 192.607.

■ 12. Section 192.67 is added to subpart A to read as follows:

§ 192.67 Records: Materials.

Each operator of transmission pipelines must acquire and retain for the life of the pipeline the original steel pipe manufacturing records that document tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured, including, but not limited to, yield strength, ultimate tensile strength, and chemical composition of materials for pipe in accordance with § 192.55.

■ 13. Section 192.127 is added to subpart B to read as follows:

§ 192.127 Records: Pipe design.

Each operator of transmission pipelines must make and retain for the life of the pipeline records documenting pipe design to withstand anticipated external pressures and loads in accordance with § 192.103 and determination of design pressure for steel pipe in accordance with § 192.105.

■ 14. In § 192.150, paragraph (a) is revised to read as follows:

§ 192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new

transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices, in accordance with the requirements and recommendations in NACE SP0102–2010, section 7 (incorporated by reference, *see* § 192.7).

* * * * *

■ 15. Section 192.205 is added to subpart D to read as follows:

§ 192.205 Records: Pipeline components.

Each operator of transmission pipelines must acquire and retain records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi or greater must have records documenting the manufacturing specification in effect at the time of manufacture, including, but not limited to, yield strength, ultimate tensile strength, and chemical composition of materials.

■ 16. In § 192.227, paragraph (c) is added to read as follows:

§ 192.227 Qualification of welders and welding operators.

* * * * *

(c) Records for transmission pipelines demonstrating each individual welder qualification in accordance with this section must be retained for the life of the pipeline.

■ 17. In § 192.285, paragraph (e) is added to read as follows:

§ 192.285 Plastic pipe: Qualifying persons to make joints.

* * * * *

(e) For transmission pipelines, records demonstrating plastic pipe joining qualifications in accordance with this section must be retained for the life of the pipeline.

18. In § 192.319, paragraph (d) is added to read as follows:

§ 192.319 Installation of pipe in a ditch.

* * * * *

(d) Promptly after a ditch for a steel onshore transmission line is backfilled, but not later than three months after placing the pipeline in service, the operator must perform an assessment to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). The operator must repair any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBμv for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six months of the assessment. Each operator of transmission pipelines must make and retain for the life of the pipeline records documenting the coating assessment findings and repairs.

■ 19. In § 192.452, the introductory text of paragraph (b) is revised to read as follows:

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

* * * * *

(b) *Regulated onshore gathering lines.* For any regulated onshore gathering line under § 192.9 existing on *[effective date of the final rule],* that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under § 192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

* * * * *

■ 20. In § 192.461, paragraph (a)(4) is revised and paragraph (f) is added to read as follows:

§ 192.461 External corrosion control: Protective coating.

(a) * * *

(4) Have sufficient strength to resist damage due to handling (including but not limited to transportation, installation, boring, and backfilling) and soil stress; and

* * * * *

(f) Promptly, but no later than three months after backfill of an onshore transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), conduct surveys to assess any coating damage to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). Remediate any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBμv for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six months of the assessment.

■ 21. In § 192.465, the section heading and paragraph (d) are revised and paragraph (f) is added to read as follows:

§ 192.465 External corrosion control: Monitoring and remediation.

* * * * *

(d) Each operator must promptly correct any deficiencies indicated by the inspection and testing provided in paragraphs (a), (b) and (c) of this section. Remedial action must be completed promptly, but no later than the next monitoring interval in § 192.465 or within one year, whichever is less.

* * * * *

(f) For onshore transmission lines, where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in Appendix D of this part, the operator must determine the extent of the area with inadequate cathodic protection. Close interval surveys must be conducted in both directions from the test station with a low cathodic protection (CP) reading at a minimum of approximately five foot intervals. Close interval surveys must be conducted, where practical based upon geographical, technical, or safety reasons. Close interval surveys required by this part must be completed with the protective current interrupted unless it is impractical to do so for technical or safety reasons. Remediation of areas with insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline must be performed in accordance with paragraph (d) of this section. The operator must confirm restoration of adequate cathodic protection by close interval survey over the entire area.

■ 22. In § 192.473, paragraph (c) is added to read as follows:

§ 192.473 External corrosion control: Interference currents.

* * * * *

(c) For onshore gas transmission pipelines, the program required by paragraph (a) of this section must include:

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be taken on a periodic basis including, when there are current flow increases over pipeline segment grounding design, from any co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could impact the effectiveness of cathodic protection; and

(3) Implementation of remedial actions to protect the pipeline segment from detrimental interference currents

promptly but no later than six months after completion of the survey.

■ 23. Section 192.478 is added to read as follows:

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

(a) For onshore transmission pipelines, each operator must develop and implement a monitoring and mitigation program to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects. Potentially corrosive constituents include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and free water, either by itself or in combination. Each operator must evaluate the partial pressure of each corrosive constituent by itself or in combination to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures.

(b) The monitoring and mitigation program in paragraph (a) of this section must include:

(1) At points where gas with potentially corrosive contaminants enters the pipeline, the use of gas-quality monitoring equipment to determine the gas stream constituents;

(2) Product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents;

(3) Evaluation twice each calendar year, at intervals not to exceed 7½ months, of gas stream and liquid quality samples and implementation of adjustments and mitigative measures to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

(c) If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked at least twice each calendar year, at intervals not exceeding 7½ months.

(d) Each operator must review its monitoring and mitigation program at least twice each calendar year, at intervals not to exceed 7½ months, based on the results of its gas stream sampling and internal corrosion monitoring in (a) and (b) and implement adjustments in its monitoring for and mitigation of the potential for internal corrosion due to the presence of potentially corrosive gas stream constituents.

■ 24. In § 192.485, paragraph (c) is revised to read as follows:

§ 192.485 Remedial measures: Transmission lines.

* * * * *

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, *see* § 192.7) or the procedure in PRCI PR 3–805 (R–STRENG) (incorporated by reference, *see* § 192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the procedures, including the appropriate use of class location and pipe longitudinal seam factors in pressure calculations for pipe defects. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, and crack-related defects, appropriate failure criteria must be used and justification of the criteria must be documented. Pipe and material properties used in remaining strength calculations and the pressure calculations made under this paragraph must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.

■ 25. Section 192.493 is added to subpart I to read as follows:

§ 192.493 In-line inspection of pipelines.

When conducting in-line inspection of pipelines required by this part, each operator must comply with the requirements and recommendations of API STD 1163, *In-line Inspection Systems Qualification Standard;* ANSI/ASNT ILI–PQ–2010, *In-line Inspection Personnel Qualification and Certification;* and NACE SP0102–2010, *In-line Inspection of Pipelines* (incorporated by reference, see § 192.7). Assessments may also be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102–2010, provided they comply with those sections of NACE SP0102–2010 that are applicable.

■ 26. In § 192.503, paragraph (a)(1) is revised to read as follows:

§ 192.503 General requirements.

(a) * * *

(1) It has been tested in accordance with this subpart and § 192.619, 192.620, or 192.624 to substantiate the maximum allowable operating pressure; and

* * * * *

■ 27. Section 192.506 is added to read as follows:

§ 192.506 Transmission lines: Spike hydrostatic pressure test for existing steel pipe with integrity threats.

(a) Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and has been found to have integrity threats that cannot be addressed by other means such as in-line inspection or direct assessment must be strength tested by a spike hydrostatic pressure test in accordance with this section to substantiate the proposed maximum allowable operating pressure.

(b) The spike hydrostatic pressure test must use water as the test medium.

(c) The baseline test pressure without the additional spike test pressure is the test pressure specified in § 192.619(a)(2), 192.620(a)(2), or 192.624, whichever applies.

(d) The test must be conducted by maintaining the pressure at or above the baseline test pressure for at least 8 hours as specified in § 192.505(e).

(e) After the test pressure stabilizes at the baseline pressure and within the first two hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.50 times MAOP or 105% SMYS. This spike hydrostatic pressure test must be held for at least 30 minutes.

(f) If the integrity threat being addressed by the spike test is of a time-dependent nature such as a cracking threat, the operator must establish an appropriate retest interval and conduct periodic retests at that interval using the same spike test pressure. The appropriate retest interval and periodic tests for the time-dependent threat must be determined in accordance with the methodology in § 192.624(d).

(g) *Alternative technology or alternative technical evaluation process.* Operators may use alternative technology or an alternative technical evaluation process that provides a sound engineering basis for establishing a spike hydrostatic pressure test or equivalent. If an operator elects to use alternative technology or an alternative technical evaluation process, the operator must notify PHMSA at least 180 days in advance of use in accordance with § 192.624(e). The operator must submit the alternative technical evaluation to the Associate Administrator of Pipeline Safety with the notification and must obtain a ''no objection letter'' from the Associate Administrator of Pipeline Safety prior to usage of alternative technology or an alternative technical evaluation process.

The notification must include the following details:

(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;

(2) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;

(3) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;

(4) Assessment techniques and acceptance criteria;

(5) Remediation methods for assessment findings;

(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;

(7) Procedures for remaining crack growth analysis and pipe segment life analysis for the time interval for additional assessments, as required; and

(8) Evidence of a review of all procedures and assessments by a subject matter expert(s) in both metallurgy and fracture mechanics.

■ 28. In § 192.517, the introductory text of paragraph (a) is revised to read as follows:

§ 192.517 Records.

(a) Each operator must make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505, 192.506, and 192.507. The record must contain at least the following information:

* * * * *

■ 29. In § 192.605, paragraph (b)(5) is revised to read as follows:

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

* * * * *

(b) * * *

(5) Operating pipeline controls and systems and operating and maintaining pressure relieving or pressure limiting devices, including those for starting up and shutting down any part of the pipeline, so that the MAOP limit as prescribed by this part cannot be exceeded by more than the margin (build-up) allowed for operation of pressure relieving devices or pressure-limiting or control devices as specified in § 192.201, 192.620(e), 192.731, 192.739, or 192.743, whichever applies.

* * * * *

■ 30. Section 192.607 is added to read as follows:

§ 192.607 Verification of pipeline material: Onshore steel transmission pipelines.

(a) *Applicable locations.* Each operator must follow the requirements of paragraphs (b) through (d) of this section for each segment of onshore, steel, gas transmission pipeline installed before *[effective date of the final rule]* that does not have reliable, traceable, verifiable, and complete material documentation records for line pipe, valves, flanges, and components and meets any of the following conditions:

(1) The pipeline is located in a High Consequence Area as defined in § 192.903; or

(2) The pipeline is located in a class 3 or class 4 location.

(b) *Material documentation plan.* Each operator must prepare a material documentation plan to implement all actions required by this section by *[date 180 days after the effective date of the final rule].*

(c) *Material documentation.* Each operator must have reliable, traceable, verifiable, and complete records documenting the following:

(1) For line pipe and fittings, records must document diameter, wall thickness, grade (yield strength and ultimate tensile strength), chemical composition, seam type, coating type, and manufacturing specification.

(2) For valves, records must document either the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating. For valves with pipe weld ends, records must document the valve material grade and weld end bevel condition to ensure compatibility with pipe end conditions;

(3) For flanges, records must document either the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating, and the material grade and weld end bevel condition to ensure compatibility with pipe end conditions;

(4) For components, records must document the applicable standards to which the component was manufactured to ensure pressure rating compatibility.

(d) *Verification of material properties.* For any material documentation records for line pipe, valves, flanges, and components specified in paragraph (c) of this section that are not available, the operator must take the following actions to determine and verify the physical characteristics.

(1) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for line pipe at all above ground locations.

(2) Develop and implement procedures for conducting destructive tests, examinations, and assessments for buried line pipe at all excavations associated with replacements or relocations of pipe segments that are removed from service.

(3) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for buried line pipe at all excavations associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, or any other reason for which the pipe segment is exposed, except for segments exposed during excavation activities that are in compliance with § 192.614, until completion of the minimum number of excavations as follows:

(i) The operator must define a separate population of undocumented or inadequately documented pipeline segments for each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a two year interval) and construction dates (within a two year interval).

(ii) Assessments must be proportionally spaced throughout the pipeline segment. Each length of the pipeline segment equal to 10 percent of the total length must contain 10 percent of the total number of required excavations, *e.g.* a 200 mile population would require 15 excavations for each 20 miles. For each population defined according to paragraph (d)(3)(i) of this section, the minimum number of excavations at which line pipe must be tested to verify pipeline material properties is the lesser of the following:

(A) 150 excavations; or

(B) If the segment is less than 150 miles, a number of excavations equal to the population's pipeline mileage (*i.e.,* one set of properties per mile), rounded up to the nearest whole number. The mileage for this calculation is the cumulative mileage of pipeline segments in the population without reliable, traceable, verifiable, and complete material documentation.

(iii) At each excavation, tests for material properties must determine diameter, wall thickness, yield strength, ultimate tensile strength, Charpy v-notch toughness (where required for failure pressure and crack growth analysis), chemical properties, seam type, coating type, and must test for the presence of stress corrosion cracking, seam cracking, or selective seam weld corrosion using ultrasonic inspection, magnetic particle, liquid penetrant, or other appropriate non-destructive examination techniques. Determination of material property values must

conservatively account for measurement inaccuracy and uncertainty based upon comparison with destructive test results using unity charts.

(iv) If non-destructive tests are performed to determine strength or chemical composition, the operator must use methods, tools, procedures, and techniques that have been independently validated by subject matter experts in metallurgy and fracture mechanics to produce results that are accurate within 10% of the actual value with 95% confidence for strength values, within 25% of the actual value with 85% confidence for carbon percentage and within 20% of the actual value with 90% confidence for manganese, chromium, molybdenum, and vanadium percentage for the grade of steel being tested.

(v) The minimum number of test locations at each excavation or above-ground location is based on the number of joints of line pipe exposed, as follows:

(A) 10 joints or less: one set of tests for each joint.

(B) 11 to 100 joints: one set of tests for each five joints, but not less than 10 sets of tests.

(C) Over 100 joints: one set of tests for each 10 joints, but not less than 20 sets of tests.

(vi) For non-destructive tests, at each test location, a set of material properties tests must be conducted at a minimum of five places in each circumferential quadrant of the pipe for a minimum total of 20 test readings at each pipe cylinder location.

(vii) For destructive tests, at each test location, a set of materials properties tests must be conducted on each circumferential quadrant of a test pipe cylinder removed from each location, for a minimum total of four tests at each location.

(viii) If the results of all tests conducted in accordance with paragraphs (d)(3)(i) and (ii) of this section verify that material properties are consistent with all available information for each population, then no additional excavations are necessary. However, if the test results identify line pipe with properties that are not consistent with existing expectations based on all available information for each population, then the operator must perform tests at additional excavations. The minimum number of excavations that must be tested depends on the number of inconsistencies observed between as-found tests and available operator records, in accordance with the following table:

Number of excavations with inconsistency between test results and existing expectations based on all available information for each population	Minimum number of total required excavations for population. The lesser of:
0	150 (or pipeline mile-age)
1	225 (or pipeline mile-age times 1.5)
2	300 (or pipeline mile-age times 2)
>2	350 (or pipeline mile-age times 2.3)

(ix) The tests conducted for a single excavation according to the requirements of paragraphs (d)(3)(iii) through (vii) of this section count as one sample under the sampling requirements of paragraphs (d)(3)(i), (ii), and (viii) of this section.

(4) For mainline pipeline components other than line pipe, the operator must develop and implement procedures for establishing and documenting the ANSI rating and material grade (to assure compatibility with pipe ends).

(i) Materials in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, operator piping, or cross-connections with isolation valves from the mainline pipeline are not required to be tested for chemical and mechanical properties.

(ii) Verification of mainline material properties is required for non-line pipe components, including but not limited to, valves, flanges, fittings, fabricated assemblies, and other pressure retaining components appurtenances that are:

(A) 2-inch nominal diameter and larger; or

(B) Material grades greater than 42,000 psi (X–42); or

(C) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

(iii) Procedures for establishing material properties for non-line pipe components where records are inadequate must be based upon documented manufacturing specifications. Where specifications are not known, usage of manufacturer's stamped or tagged material pressure ratings and material type may be used to establish pressure rating. The operator must document the basis of the material properties established using such procedures.

(5) The material properties determined from the destructive or non-destructive tests required by this section cannot be used to raise the original grade or specification of the material, which must be based upon the applicable standard referenced in § 192.7.

(6) If conditions make material verification by the above methods impracticable or if the operator chooses to use ''other technology'' or ''new technology'' (alternative technical evaluation process plan), the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph § 192.624(e) of this section. The operator must submit the alternative technical evaluation process plan to the Associate Administrator of Pipeline Safety with the notification and must obtain a ''no objection letter'' from the Associate Administrator of Pipeline Safety prior to usage of an alternative evaluation process.

■ 31. In § 192.613, paragraph (c) is added to read as follows:

§ 192.613 Continuing surveillance.

* * * * *

(c) Following an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar event that has the likelihood of damage to infrastructure, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

(1) *Inspection method.* An operator must consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine damage and the need for the additional assessments required under the introductory text of paragraph (c) in this section.

(2) *Time period.* The inspection required under the introductory text of paragraph (c) of this section must commence within 72 hours after the cessation of the event, defined as the point in time when the affected area can be safely accessed by the personnel and equipment, including availability of personnel and equipment, required to perform the inspection as determined under paragraph (c)(1) of this section, whichever is sooner.

(3) *Remedial action.* An operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required under the introductory text of paragraph (c) in this section. Such

actions might include, but are not limited to:

(i) Reducing the operating pressure or shutting down the pipeline;

(ii) Modifying, repairing, or replacing any damaged pipeline facilities;

(iii) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;

(iv) Performing additional patrols, surveys, tests, or inspections;

(v) Implementing emergency response activities with Federal, State, or local personnel; or

(vi) Notifying affected communities of the steps that can be taken to ensure public safety.

■ 32. In § 192.619, paragraphs (a)(2) through (4) are revised and paragraphs (e) and (f) are added to read as follows:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) * * *

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors [1], segment—			
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970) and before *[effective date of the final rule]*	Installed after *[effective date of the final rule minus 1 day]*	Converted under § 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1] For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than § 192.612) after April 13, 2006 but before *[effective date of the final rule]*.	March 15, 2006, or date line becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
—Onshore gathering line that first became subject to this part (other than § 192.612) on or after *[effective date of the final rule]*.	*[date one year after effective date of the final rule]*, or date line becomes subject to this part, whichever is later.	
—Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.	March 15, 2006, or date line becomes subject to this part, whichever is later.	
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering material records, including material properties verified in accordance with § 192.607, and the history of the segment, particularly known corrosion and the actual operating pressure.

* * * * *

(e) Notwithstanding the requirements in paragraphs (a) through (d) of this section, onshore steel transmission pipelines that meet the criteria specified in § 192.624(a) must establish and document the maximum allowable operating pressure in accordance with § 192.624 using one or more of the following:

(1) Method 1: Pressure Test—Pressure test in accordance with § 192.624(c)(1)(i) or spike hydrostatic pressure test in accordance with § 192.624(c)(1)(ii), as applicable;

(2) Method 2: Pressure Reduction—Reduction in pipeline maximum allowable operating pressure in accordance with § 192.624(c)(2);

(3) Method 3: Engineering Critical Assessment—Engineering assessment and analysis activities in accordance with § 192.624(c)(3);

(4) Method 4: Pipe Replacement—Replacement of the pipeline segment in accordance with § 192.624(c)(4);

(5) Method 5: Pressure Reduction for Segments with Small PIR and Diameter—Reduction of maximum allowable operating pressure and other preventive measures for pipeline segments with small PIRs and diameters, in accordance with § 192.624(c)(5); or

(6) Method 6: Alternative Technology—Alternative procedure in accordance with § 192.624(c)(6).

(f) Operators must maintain all records necessary to establish and document the MAOP of each pipeline as long as the pipe or pipeline remains in service. Records that establish the pipeline MAOP, include, but are not limited to, design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data. Records must be reliable, traceable, verifiable, and complete.

■ 33. Section 192.624 is added to read as follows:

§ 192.624 Maximum allowable operating pressure verification: Onshore steel transmission pipelines.

(a) *Applicable locations.* The operator of a pipeline segment meeting any of the following conditions must establish the maximum allowable operating pressure using one or more of the methods specified in § 192.624(c)(1) through (6):

(1) The pipeline segment has experienced a reportable in-service incident, as defined in § 191.3 of this chapter, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations:

(i) A high consequence area as defined in § 192.903;

(ii) A class 3 or class 4 location; or

(iii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

(2) Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline is located in one of the following locations:

(i) A high consequence area as defined in § 192.903; or

(ii) A class 3 or class 4 location

(3) The pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) before [*effective date of the final rule*] and is located in one of the following areas:

(i) A high consequence area as defined in § 192.903;

(ii) A class 3 or class 4 location; or

(iii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

(b) *Completion date.* For pipelines installed before [*effective date of the final rule*], all actions required by this section must be completed according to the following schedule:

(1) The operator must develop and document a plan for completion of all actions required by this section by *[date 1 year after effective date of the final rule].*

(2) The operator must complete all actions required by this section on at least 50% of the mileage of locations that meet the conditions of § 192.624(a) by *[date 8 years after effective date of the final rule].*

(3) The operator must complete all actions required by this section on 100% of the mileage of locations that meet the conditions of § 192.624(a) by *[date 15 years after effective date of the final rule].*

(4) If operational and environmental constraints limit the operator from meeting the deadlines in § 192.614(b)(2) and (3), the operator may petition for an extension of the completion deadlines by up to one year, upon submittal of a notification to the Associate Administrator of the Office of Pipeline Safety in accordance with paragraph (e) of this section. The notification must include an up-to-date plan for completing all actions in accordance with paragraph (b)(1) of this section, the reason for the requested extension, current status, proposed completion date, remediation activities outstanding, and any needed temporary safety measures to mitigate the impact on safety.

(c) *Maximum allowable operating pressure determination.* The operator of a pipeline segment meeting the criteria in paragraph (a) of this section must establish its maximum allowable operating pressure using one of the following methods:

(1) *Method 1: Pressure test.*(i) Perform a pressure test in accordance with § 192.505(c). The maximum allowable operating pressure will be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

(ii) If the pipeline segment includes legacy pipe or was constructed using legacy construction techniques or the pipeline has experienced an incident, as defined by § 191.3 of this chapter, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking, then the operator must perform a spike pressure test in accordance with § 192.506. The maximum allowable operating pressure will be equal to the test pressure specified in § 192.506(c) divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

(iii) If the operator has reason to believe any pipeline segment may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph (d) of this section.

(2) *Method 2: Pressure reduction.* The pipeline maximum allowable operating pressure will be no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding *[effective date of the final rule]* divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest pressure value for the entire segment or using the operating pressure gradient (*i.e.,* the location-specific operating pressure at each location).

(i) Where the pipeline segment has had a class location change in accordance with § 192.611 and pipe material and pressure test records are not available, the operator must reduce the pipeline segment MAOP as follows:

(A) For segments where a class location changed from 1 to 2, from 2 to 3, or from 3 to 4, reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding *[effective date of the final rule],* divided by 1.39 for class 1 to 2, 1.67 for class 2 to 3, and 2.00 for class 3 to 4.

(B) For segments where a class location changed from 1 to 3, reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding *[effective date of the final rule],* divided by 2.00.

(ii) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph (d) of this section.

(iii) Future uprating of the segment in accordance with subpart K of this part is allowed if the maximum allowable operating pressure is established using Method 2 described in paragraph (c)(2) of this section.

(iv) If an operator elects to use Method 2 described in paragraph (c)(2) of this section, but desires to use a less conservative pressure reduction factor, the operator must notify PHMSA in accordance with paragraph (e) of this section no later than seven calendar days after establishing the reduced maximum allowable operating pressure.

The notification must include the following details:

(A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 192.624(c)(2);

(B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with paragraph (d) of this section;

(C) Justification that establishing maximum allowable operating pressure by another method allowed by this section is impractical;

(D) Justification that the reduced maximum allowable operating pressure determined by the operator is safe based on analysis of the condition of the pipeline segment, including material records, material properties verified in accordance § 192.607, and the history of the segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned.

(E) Planned duration for operating at the requested maximum allowable operating pressure, long term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts in metallurgy and fracture mechanics.

(3) *Method 3: Engineering critical assessment.* Conduct an engineering critical assessment and analysis (ECA) to establish the material condition of the segment and maximum allowable operating pressure. An ECA is an analytical procedure, based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections. The ECA must assess: threats; loadings and operational circumstances relevant to those threats including along the right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; initial and final defect size relevance. The ECA must quantify the coupled effects of any defect in the pipeline.

(i) *ECA analysis.* (A) The ECA must integrate and analyze the results of the material documentation program required by § 192.607, if applicable, and the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including but not limited to close interval surveys, coating surveys, and interference surveys required by subpart I of this part, root cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by § 192.710 and subpart O of this part.

(B) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure (PFP) of each defect. The ECA must use the techniques and procedures in Battelle Final Reports (''Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications''—Task 1.4), Report No. 13–002 (''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams''—Subtask 2.4), Report No. 13–021 (''Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue''—Subtask 2.5) and (''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1''—Task 4.5) (incorporated by reference, *see* § 192.7) or other technically proven methods including but not limited to API RP 579–1/ASME FFS–1, June 5, 2007, (API 579–1, Second Edition)—Level II or Level III, CorLas™, or PAFFC. The ECA must use conservative assumptions for crack dimensions (length and depth) and failure mode (ductile, brittle, or both) for the microstructure, location, type of defect, and operating conditions (which includes pressure cycling). If actual material toughness is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must determine a Charpy v-notch toughness based upon the material documentation program specified in § 192.607 or use conservative values for Charpy v-notch toughness as follows: body toughness of less than or equal to 5.0 ft-lb and seam toughness of less than or equal to 1 ft-lb.

(C) The ECA must analyze any metal loss defects not associated with a dent including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe to determine the predicted failure pressure (PFP). ASME/ANSI B31G (incorporated by reference, see § 192.7) or AGA Pipeline Research Committee Project PR–3–805 (''RSTRENG,'' incorporated by reference, see § 192.7) must be used for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth). When determining PFP for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607.

(D) The ECA must analyze interacting defects to conservatively determine the most limiting PFP for interacting defects. Examples include but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

(E) The maximum allowable operating pressure must be established at the lowest PFP for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

(ii) *Use of prior pressure test.* If pressure test records as described in subpart J of this part and § 192.624(c)(1) exist for the segment, then an in-line inspection program is not required, provided that the remaining life of the most severe defects that could have survived the pressure test have been calculated and a re-assessment interval has been established. The appropriate retest interval and periodic tests for time-dependent threats must be determined in accordance with the methodology in § 192.624(d) *Fracture mechanics modeling for failure stress and crack growth analysis.*

(iii) *In-line inspection.* If the segment does not have records for a pressure test in accordance with subpart J of this part and § 192.624(c)(1), the operator must develop and implement an inline inspection (ILI) program using tools that can detect wall loss, deformation from

dents, wrinkle bends, ovalities, expansion, seam defects including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking. At a minimum, the operator must conduct an assessment using high resolution magnetic flux leakage (MFL) tool, a high resolution deformation tool, and either an electromagnetic acoustic transducer (EMAT) or ultrasonic testing (UT) tool.

(A) In lieu of the tools specified in paragraph § 192.624(c)(3)(i), an operator may use ''other technology'' if it is validated by a subject matter expert in metallurgy and fracture mechanics to produce an equivalent understanding of the condition of the pipe. If an operator elects to use ''other technology,'' it must notify the Associate Administrator of Pipeline Safety, at least 180 days prior to use, in accordance with paragraph (e) of this section and receive a ''no objection letter'' from the Associate Administrator of Pipeline Safety prior to its usage. The ''other technology'' notification must have:

(*1*) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments including characterization of defect size crack assessments (length, depth, and volumetric); and

(*2*) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and remediate defects discovered.

(B) If the operator has information that indicates a pipeline includes segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.

(C) If the pipeline has had a reportable incident, as defined in § 192.3, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with paragraph § 192.624(c)(3)(iii) includes an engineering evaluation program to analyze the susceptibility of girth weld failure due to lateral stresses.

(D) Inline inspection must be performed in accordance with § 192.493.

(E) All MFL and deformation tools used must have been validated to characterize the size of defects within 10% of the actual dimensions with 90% confidence. All EMAT or UT tools must have been validated to characterize the size of cracks, both length and depth, within 20% of the actual dimensions with 80% confidence, with like-similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.

(F) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and subpart O of this part, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the type defects and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.

(G) Anomalies detected by ILI assessments must be repaired in accordance with applicable repair criteria in §§ 192.713 and 192.933.

(iv) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.624(d).

(4) *Method 4: Pipe replacement.* Replace the pipeline segment.

(5) *Method 5: Pressure reduction for segments with small potential impact radius and diameter.* Pipelines with a maximum allowable operating pressure less than 30 percent of specified minimum yield strength, a potential impact radius (PIR) less than or equal to 150 feet, nominal diameter equal to or less than 8-inches, and which cannot be assessed using inline inspection or pressure test, may establish the maximum allowable operating pressure as follows:

(i) Reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline during 18 months preceding *[effective date of the final rule],* divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of eight hours during one continuous 30-day period. The reduced maximum allowable operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire segment or the operating pressure gradient (*i.e.,* the location specific operating pressure at each location);

(ii) Conduct external corrosion direct assessment in accordance with § 192.925, and internal corrosion direct assessment in accordance with § 192.927;

(iii) Develop and implement procedures for conducting non-destructive tests, examinations, and assessments for cracks and crack-like defects, including but not limited to stress corrosion cracking, selective seam weld corrosion, girth weld cracks, and seam defects, for pipe at all excavations associated with anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, or any other reason for which the pipe segment is exposed, except for segments exposed during excavation activities that are in compliance with § 192.614;

(iv) Conduct monthly patrols in Class 1 and 2 locations, at an interval not to exceed 45 days; weekly patrols in Class 3 locations not to exceed 10 days; and semi-weekly patrols in Class 4 locations, at an interval not to exceed six days, in accordance with § 192.705;

(v) Conduct monthly, instrumented leakage surveys in Class 1 and 2 locations, at intervals not to exceed 45 days; weekly leakage surveys in Class 3 locations at intervals not to exceed 10 days; and semi-weekly leakage surveys in Class 4 locations, at intervals not to exceed six days, in accordance with § 192.706; and

(vi) Odorize gas transported in the segment, in accordance with § 192.625;

(vii) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.624(d).

(viii) Under Method 5 described in paragraph (c)(5) of this section, future uprating of the segment in accordance with subpart K of this part is allowed.

(6) *Method 6: Alternative technology.* Operators may use an alternative technical evaluation process that provides a sound engineering basis for establishing maximum allowable operating pressure. If an operator elects to use alternative technology, the

operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph (e) of this section. The operator must submit the alternative technical evaluation to PHMSA with the notification and obtain a ''no objection letter'' from the Associate Administrator of Pipeline Safety prior to usage of alternative technology. The notification must include the following details:

(i) Descriptions of the technology or technologies to be used for tests, examinations, and assessments, establishment of material properties, and analytical techniques, with like-similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.

(ii) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;

(iii) Methodology and criteria used to determine reassessment period or need for a reassessment including references to applicable regulations from this part and industry standards;

(iv) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;

(v) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of PFP quantified as a fraction of specified minimum yield strength;

(vi) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph (d) of this section;

(vii) Remediation methods with proven technical practice;

(viii) Schedules for assessments and remediation;

(ix) Operational monitoring procedures;

(x) Methodology and criteria used to justify and establish the maximum allowable operating pressure; and

(xi) Documentation requirements for the operator's process, including records to be generated.

(d) *Fracture mechanics modeling for failure stress and crack growth analysis.* (1) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must perform fracture mechanics modeling for failure stress pressure and crack growth analysis to determine the remaining life of the pipeline at the maximum allowable operating pressure based on the applicable test pressures in accordance with § 192.506 including the remaining crack flaw size in the pipeline segment, any pipe failure or leak mechanisms identified during pressure testing, pipe characteristics, material toughness, failure mechanism for the microstructure(ductile and brittle or both), location and type of defect, operating environment, and operating conditions including pressure cycling. Fatigue analysis must be performed using a recognized form of the Paris Law as specified in Battelle's Final Report No. 13–021; Subtask 2.5 (incorporated by reference, see § 192.7) or other technically appropriate engineering methodology validated by a subject matter expert in metallurgy and fracture mechanics to give conservative predictions of flaw growth and remaining life. When assessing other degradation processes, the analysis must be performed using recognized rate equations whose applicability and validity is demonstrated for the case being evaluated. For cases involving calculation of the critical flaw size, conservative remaining life analysis must assess the smallest critical sizes and use a lower-bound toughness. For cases dealing with an estimating of the defect sizes that would survive a hydro test pressure, conservative remaining life analysis that must assess the largest surviving sizes and use upper-bound values of material strength and toughness. The analysis must include a sensitivity analysis to determine conservative estimates of time to failure for cracks. Material strength and toughness values used must reflect the local conditions for growth, and use data that is case specific to estimate the range of strength and toughness for such analysis. When the strength and toughness and limits on their ranges are unknown, the analysis must assume material strength and fracture toughness levels corresponding to the type of assessment being performed, as follows:

(i) For an assessment using a hydrostatic pressure test use a full size equivalent Charpy upper-shelf energy level of 120 ft-lb and a flow stress equal to the minimum specified ultimate tensile strength of the base pipe material. The purpose of using the high level of Charpy energy and flow stress (equal to the ultimate tensile strength) is for an operator to calculate the largest defects that could have survived a given level of hydrostatic test. The resulting maximum-size defects lead to the shortened predicted times to failure,

(ii) For ILI assessments unless actual ranges of values of strength and toughness are known, the analysis must use the specified minimum yield strength and the specified minimum ultimate tensile strength and Charpy toughness valves lower than or equal to: 5.0 ft-lb for body cracks; 1.0 ft-lb for ERW seam bond line defects such as cold weld, lack of fusion, and selective seam weld corrosion defects.

(iii) The sensitivity analysis to determine the time to failure for a crack must include operating history, pressure tests, pipe geometry, wall thickness, strength level, flow stress, and operating environment for the pipe segment being assessed, including at a minimum the role of the pressure-cycle spectrum.

(2) If actual material toughness is not known or not adequately documented for fracture mechanics modeling for failure stress pressure, the operator must use a conservative Charpy energy value to determine the toughness based upon the material documentation program specified in § 192.607; or use maximum Charpy energy values of 5.0 ft-lb for body cracks; 1.0 ft-lb for cold weld, lack of fusion, and selective seam weld corrosion defects as documented in Battelle Final Reports (''Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications''—Task 1.4), No. 13–002 (''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams''—Subtask 2.4), Report No. 13–021 (''Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue''—Subtask 2.5) and (''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1''—Task 4.5) (incorporated by reference, *see* § 192.7); or other appropriate technology or technical publications that an operator demonstrates can provide a conservative Charpy energy values of the crack-related conditions of the line pipe.

(3) The analysis must account for metallurgical properties at the location being analyzed (such as in the properties of the parent pipe, weld heat affected zone, or weld metal bond line), and must account for the likely failure mode of anomalies (such as brittle fracture, ductile fracture or both). If the likely failure mode is uncertain or unknown, the analysis must analyze both failure modes and use the more conservative result. Appropriate fracture

mechanics modeling for failure stress pressures in the brittle failure mode is the Raju/Newman Model (Task 4.5) and for the ductile failure mode is the Modified LnSec (Task 4.5) and Raju/Newman Models or other proven-equivalent engineering fracture mechanics models for determining conservative failure pressures may be used.

(4) If the predicted remaining life of the pipeline calculated by this analysis is 5 years or less, then the operator must perform a pressure test in accordance with paragraph (c)(1) of this section or reduce the maximum allowable operating pressure of the pipeline in accordance with paragraph (c)(2) of this section to establish the maximum allowable operating pressure within 1-year of analysis;

(5) The operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired, but within 15 years. The operator must determine and document if further pressure tests or use of other methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired. If the analysis results show that a 50% remaining life reduction does not give a sufficient safety factor based upon technical evaluations then a more conservative remaining life safety factor must be used.

(6) The analysis required by this paragraph (d) of this section must be reviewed and confirmed by a subject matter expert in both metallurgy and fracture mechanics.

(e) *Notifications.* An operator must submit all notifications required by this section to the Associate Administrator for Pipeline Safety, by:

(1) Sending the notification to the Office of Pipeline Safety, Pipeline and Hazardous Material Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue SE., Washington, DC 20590–0001;

(2) Sending the notification to the Information Resources Manager by facsimile to (202) 366–7128; or

(3) Sending the notification to the Information Resources Manager by email to *InformationResourcesManager@dot.gov.*

(4) An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

(f) *Records.* Each operator must keep for the life of the pipeline reliable, traceable, verifiable, and complete records of the investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions made in accordance with the requirements of this section.

■ 34. Section 192.710 is added to read as follows:

§ 192.710 Pipeline assessments.

(a) *Applicability.* (1) This section applies to onshore transmission pipeline segments that are located in:

(i) A class 3 or class 4 location; or

(ii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ‘‘smart pigs’’).

(2) This section does not apply to a pipeline segment located in a high consequence area as defined in § 192.903.

(b) *General.* (1) An operator must perform initial assessments in accordance with this section no later than *[date 15 years after effective date of the final rule]* and periodic reassessments every 20 years thereafter, or a shorter reassessment internal based upon the type anomaly, operational, material, and environmental conditions found on the pipeline segment, or as otherwise necessary to ensure public safety.

(2) *Prior assessment.* An operator may use a prior assessment conducted before *[effective date of the final rule]* as an initial assessment for the segment, if the assessment meets the subpart O of this part requirements for in-line inspection. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(1) of this section.

(3) *MAOP verification.* An operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

(c) *Assessment method.* The initial assessments and the reassessments required by paragraph (b) of this section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline is susceptible and must be performed using one or more of the following methods:

(1) Internal inspection tool or tools capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots, and any other threats to which the segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493;

(2) Pressure test conducted in accordance with subpart J of this part. The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, manufacturing and related defect threats, including defective pipe and pipe seams, dents and other forms of mechanical damage;

(3) ‘‘Spike’’ hydrostatic pressure test in accordance with § 192.506;

(4) Excavation and *in situ* direct examination by means of visual examination and direct measurement and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI);

(5) Guided wave ultrasonic testing (GWUT) as described in appendix F;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospitals and nursing homes) using the methods specified in paragraphs (d)(1) through (5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 or 192.929; or

(7) Other technology or technologies that an operator demonstrates can provide an equivalent understanding of the line pipe for each of the threats to which the pipeline is susceptible.

(8) For segments with MAOP less than 30% of the SMYS, an operator must assess for the threats of external and internal corrosion, as follows:

(i) *External corrosion.* An operator must take one of the following actions to address external corrosion on a low stress segment:

(A) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe, an operator must perform an indirect assessment (*i.e.* indirect examination

tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) at least every seven years on the segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(B) *Unprotected pipe or cathodically protected pipe where indirect assessments are impractical.* To address the threat of external corrosion on unprotected pipe or cathodically protected pipe where indirect assessments are impractical, an operator must—

(*1*) Conduct leakage surveys as required by § 192.706 at 4-month intervals; and

(*2*) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(ii) *Internal corrosion.* To address the threat of internal corrosion on a low stress segment, an operator must—

(A) Conduct a gas analysis for corrosive agents at least twice each calendar year;

(B) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a segment; and

(C) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(8)(ii)(A) and (B) of this section with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

(d) *Data analysis.* A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment performed under paragraph (b) of this section to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing anomalies.

(e) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information to determine that a condition exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to make the determination required under paragraph (d), unless the operator can demonstrate that that 180-days is impracticable.

(f) *Remediation.* An operator must comply with the requirements in § 192.713 if a condition that could adversely affect the safe operation of a pipeline is discovered.

(g) *Consideration of information.* An operator must consider all available information about a pipeline in complying with the requirements in paragraphs (a) through (f) of this section.

■ 35. In § 192.711, paragraph (b)(1) is revised to read as follows:

§ 192.711 Transmission lines: General requirements for repair procedures.

* * * * *

(b) * * *

(1) *Non integrity management repairs.* Whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered under subpart O of this part, Gas Transmission Pipeline Integrity Management, it must correct the condition as prescribed in § 192.713. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator must reduce the operating pressure to a level not exceeding 80% of the operating pressure at the time the condition was discovered and take additional immediate temporary measures in accordance with paragraph (a) of this section to protect persons or property. The operator must make permanent repairs as soon as feasible.

* * * * *

■ 36. Section 192.713 is revised to read as follows:

§ 192.713 Transmission lines: Permanent field repair of imperfections and damages.

(a) *This section applies to transmission lines.* Line segments that are located in high consequence areas, as defined in § 192.903, must also comply with applicable actions specified by the integrity management requirements in subpart O of this part.

(b) *General.* Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made so as to prevent damage to persons, property, or the environment. Operating pressure must be at a safe level during repair operations.

(c) *Repair.* Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(d) *Remediation schedule.* For pipelines not located in high consequence areas, an operator must complete the remediation of a condition according to the following schedule:

(1) *Immediate repair conditions.* An operator must repair the following conditions immediately upon discovery:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in § 192.7(c). Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

(iii) Metal loss greater than 80% of nominal wall regardless of dimensions.

(iv) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high frequency electric resistance welding or by electric flash welding.

(v) Any indication of significant stress corrosion cracking (SCC).

(vi) Any indication of significant selective seam weld corrosion (SSWC).

(vii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(2) Until the remediation of a condition specified in paragraph (d)(1) of this section is complete, an operator must reduce the operating pressure of the affected pipeline to the lower of:

(i) A level that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, determined using ASME/ANSI B31G (''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991) or AGA Pipeline Research Committee Project PR–3–805 (''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 1989)) (''RSTRENG,'' incorporated by reference, see § 192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607; or

(ii) 80% of pressure at the time of discovery, whichever is lower.

(3) *Two-year conditions.* An operator must repair the following conditions within two years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than nominal pipe size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld.

(iii) A calculation of the remaining strength of the pipe shows a predicted failure pressure ratio (FPR) at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations. This calculation must adequately account for the uncertainty associated with the accuracy of the tool used to perform the assessment.

(iv) An area of corrosion with a predicted metal loss greater than 50% of nominal wall.

(v) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.

(vi) A gouge or groove greater than 12.5% of nominal wall.

(vii) Any indication of crack or crack-like defect other than an immediate condition.

(4) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than nominal pipe size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(e) *Other conditions.* Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules and methods defined in the operator's Operating and Maintenance procedures.

(f) *In situ direct examination of crack defects.* Whenever required by this part, operators must perform direct examination of known locations of cracks or crack-like defects using inverse wave field extrapolation (IWEX), phased array, automated ultrasonic testing (AUT), or equivalent technology that has been validated to detect tight cracks (equal to or less than 0.008 inches). In-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection and in metallurgy and fracture mechanics for accuracy for the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

■ 37. Section 192.750 is added to read as follows:

§ 192.750 Launcher and receiver safety.

Any launcher or receiver used after *[date 6 months after effective date of the final rule],* must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. The operator must use a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent opening of the barrel closure or flange, or prevent insertion or removal of in-line inspection tools, scrapers, or spheres, if pressure has not been relieved.

■ 38. In § 192.911, paragraph (k) is revised to read as follows:

§ 192.911 What are the elements of an integrity management program?

* * * * *

(k) A management of change process as required by § 192.13(d).

* * * * *

■ 39. In § 192.917, paragraphs (a), (b), (c), (d), (e)(2), (e)(3), and (e)(4) are revised to read as follows:

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 2, which are grouped under the following four threats:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Stable threats, such as manufacturing, welding/fabrication, or equipment defects;

(3) Time independent threats such as third party/mechanical damage, incorrect operational procedure, weather related and outside force, including consideration of seismicity, geology, and soil stability of the area; and

(4) Human error such as operational mishaps and design and construction mistakes.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather, verify, validate, and integrate existing data and

information on the entire pipeline that could be relevant to the covered segment. In performing data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in paragraph (b)(1) of this section and appendix A to ASME/ANSI B31.8S. The evaluation must analyze both the covered segment and similar non-covered segments, and must:

(1) Integrate information about pipeline attributes and other relevant information, including, but not limited to:

(i) Pipe diameter, wall thickness, grade, seam type and joint factor;

(ii) Manufacturer and manufacturing date, including manufacturing data and records;

(iii) Material properties including, but not limited to, diameter, wall thickness, grade, seam type, hardness, toughness, hard spots, and chemical composition;

(iv) Equipment properties;

(v) Year of installation;

(vi) Bending method;

(vii) Joining method, including process and inspection results;

(viii) Depth of cover surveys including stream and river crossings, navigable waterways, and beach approaches;

(ix) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;

(x) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;

(xi) Pipe coating methods (both manufactured and field applied) including method or process used to apply girth weld coating, inspection reports, and coating repairs;

(xii) Soil, backfill;

(xiii) Construction inspection reports, including but not limited to:

(A) Girth weld non-destructive examinations;

(B) Post backfill coating surveys;

(C) Coating inspection (''jeeping'') reports;

(xiv) Cathodic protection installed, including but not limited to type and location;

(xv) Coating type;

(xvi) Gas quality;

(xvii) Flow rate;

(xviii) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);

(xix) Class location;

(xx) Leak and failure history including any in-service ruptures or leaks from incident reports, abnormal operations, safety related conditions (both reported and unreported) and failure investigations required by § 192.617, and their identified causes and consequences;

(xxi) Coating condition;

(xxii) CP system performance;

(xxiii) Pipe wall temperature;

(xxiv) Pipe operational and maintenance inspection reports, including but not limited to:

(A) Data gathered through integrity assessments required under this part, including but not limited to in-line inspections, pressure tests, direct assessment, guided wave ultrasonic testing, or other methods;

(B) Close interval survey (CIS) and electrical survey results;

(C) Cathodic protection (CP) rectifier readings;

(D) CP test point survey readings and locations;

(E) AC/DC and foreign structure interference surveys;

(F) Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including but not limited to direct current voltage gradient or alternating current voltage gradient inspections;

(G) Results of examinations of exposed portions of buried pipelines (*e.g.,* pipe and pipe coating condition, see § 192.459), including the results of any non-destructive examinations of the pipe, seam or girth weld, *i.e.* bell hole inspections;

(H) Stress corrosion cracking (SCC) excavations and findings;

(I) Selective seam weld corrosion (SSWC) excavations and findings;

(J) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;

(xxv) Outer Diameter/Inner Diameter corrosion monitoring;

(xxvi) Operating pressure history and pressure fluctuations, including analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;

(xxvii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;

(xxviii) Encroachments and right-of-way activity, including but not limited to, one-call data, pipe exposures resulting from encroachments, and excavation activities due to development or planned development along the pipeline;

(xxix) Repairs;

(xxx) Vandalism;

(xxxi) External forces;

(xxxii) Audits and reviews;

(xxxiii) Industry experience for incident, leak and failure history;

(xxxiv) Aerial photography;

(xxxv) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area; and

(xxxvi) Other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this part.

(2) Use objective, traceable, verified, and validated information and data as inputs, to the maximum extent practicable. If input is obtained from subject matter experts (SMEs), the operator must employ measures to adequately correct any bias in SME input. Bias control measures may include training of SMEs and use of outside technical experts (independent expert reviews) to assess quality of processes and the judgment of SMEs. Operator must document the names of all SMEs and information submitted by the SMEs for the life of the pipeline.

(3) Identify and analyze spatial relationships among anomalous information (*e.g.,* corrosion coincident with foreign line crossings; evidence of pipeline damage where overhead imaging shows evidence of encroachment). Storing or recording the information in a common location, including a geographic information system (GIS), alone, is not sufficient; and

(4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.

(c) *Risk assessment.* An operator must conduct a risk assessment that analyzes the identified threats and potential consequences of an incident for each covered segment. The risk assessment must include evaluation of the effects of interacting threats, including the potential for interactions of threats and anomalous conditions not previously evaluated. An operator must ensure validity of the methods used to conduct the risk assessment in light of incident, leak, and failure history and other historical information. Validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the

factors used to characterize both the probability of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures needed (§ 192.935) for each covered segment, and periodically evaluate the integrity of each covered pipeline segment (§ 192.937(b)). The risk assessment must:

(1) Analyze how a potential failure could affect high consequence areas, including the consequences of the entire worst-case incident scenario from initial failure to incident termination;

(2) Analyze the likelihood of failure due to each individual threat or risk factor, and each unique combination of threats or risk factors that interact or simultaneously contribute to risk at a common location;

(3) Lead to better understanding of the nature of the threat, the failure mechanisms, the effectiveness of currently deployed risk mitigation activities, and how to prevent, mitigate, or reduce those risks;

(4) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and

(5) Evaluate the potential risk reduction associated with candidate risk reduction activities such as preventive and mitigative measures and reduced anomaly remediation and assessment intervals.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.

(e) * * *

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading conditions (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment. Fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis must be conducted in accordance with § 192.624(d) for cracks. Cyclic fatigue analysis must be annually, not to exceed 15 months.

(3) *Manufacturing and construction defects.* An operator must analyze the covered segment to determine the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to hydrostatic pressure testing satisfying the criteria of subpart J of this part of at least 1.25 times MAOP, and the segment has not experienced an in-service incident attributed to a manufacturing or construction defect since the date of the pressure test. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment, and must reconfirm or reestablish MAOP in accordance with § 192.624(c).

(i) The segment has experienced an in-service incident, as described in § 192.624(a)(1);

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe, pipe with seam factor less than 1.0 as defined in § 192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including, but not limited to pipe body cracking, seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years (including abnormal operation as defined in § 192.605(c)), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment. Pipe with cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 192.624(c) and (d).

* * * * *

■ 40. In § 192.921, paragraph (a) is revised to read as follows:

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917). In addition, an operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

(1) Internal inspection tool or tools capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. A person qualified by knowledge, training, and experience must analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in table 3 of section 5 of ASME/ANSI B31.8S to justify an extended reassessment interval in accordance with § 192.939. The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, manufacturing and related defect threats, including defective pipe

and pipe seams, stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage;

(3) ''Spike'' hydrostatic pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for threats such as stress corrosion cracking, selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects;

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI);

(5) Guided Wave Ultrasonic Testing (GWUT) conducted as described in Appendix F;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in § 192.925, 192.927, or 192.929; or

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with § 192.949 and receive a ''no objection letter'' from the Associate Administrator of Pipeline Safety. An operator must also notify the appropriate State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

* * * * *

■ 41. In § 192.923, paragraphs (b)(2) and (b)(3) are revised to read as follows:

§ 192.923 How is direct assessment used and for what threats?

* * * * *

(b) * * *

(2) NACE SP0206–2006 and § 192.927 if addressing internal corrosion (ICDA).

(3) NACE SP0204–2008 and § 192.929 if addressing stress corrosion cracking (SCCDA).

* * * * *

■ 42. In § 192.927, paragraphs (b) and (c) are revised to read as follows:

§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

* * * * *

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206–2006 (incorporated by reference, *see* § 192.7). The Dry Gas (DG) Internal Corrosion Direct Assessment (ICDA) process described in this section applies only for a segment of pipe transporting normally dry natural gas (see definition § 192.3), and not for a segment with electrolyte normally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment in accordance with § 192.921(a)(4) or § 192.937(c)(4).

(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that meets all requirements and recommendations contained in NACE SP0206–2006 and that implements all four steps of the DG–ICDA process including pre-assessment, indirect inspection, detailed examination, and post-assessment. The plan must identify where all ICDA Regions with covered segments are located in the transmission system. An ICDA Region is a continuous length of pipe (including weld joints) uninterrupted by any significant change in water or flow characteristics that includes similar physical characteristics or operating history. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located in order to complete the assessment of the covered segment.

(1) *Preassessment.* An operator must comply with the requirements and recommendations in NACE SP0206–2006 in conducting the preassessment step of the ICDA process.

(2) *Indirect Inspection.* An operator must comply with the requirements and recommendations in NACE SP0206–2006, and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. Operators must explicitly document the results of its feasibility assessment as required by NACE SP0206–2006, Section 3.3; if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use pipeline specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of data used to make those calculations, including but not limited to gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossing, river crossings, drains, valves, drips, etc.), topographical data, depth of cover, etc. The operator must select locations for direct examination, and establish the extent of pipe exposure needed (*i.e.,* the size of the bell hole), to explicitly account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

(3) *Detailed examination.* An operator must comply with the requirements and recommendations in NACE SP0206–2006 in conducting the detailed examination step of the ICDA process. In addition, on the first use of ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each covered segment associated with the ICDA Region and must perform a detailed examination for internal corrosion at each location using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques. One location must be the low point (*e.g.,* sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion is found at any location, the operator must—

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with § 192.933, if the condition is in a covered segment,

or in accordance with §§ 192.485 and 192.713 if the condition is not in a covered segment;

(ii) Expand the detailed examination program, whenever internal corrosion is discovered, to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (*e.g.,* sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined per paragraph (c)(3) of this section, two additional detailed examinations must be conducted within the covered segment; and

(iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region in which the corrosion was found and remediate identified instances of internal corrosion in accordance with § 192.933 or § 192.713, as appropriate.

(4) *Post-assessment evaluation and monitoring.* An operator must comply with the requirements and recommendations in NACE SP0206–2006 in performing the post assessment step of the ICDA process. In addition to the post-assessment requirements and recommendations in NACE SP0206–2006, the evaluation and monitoring process must also include—

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in § 192.939. An operator must carry out this evaluation within a year of conducting an ICDA;

(ii) Validation of the flow modeling calculations by comparison of actual locations of discovered internal corrosion with locations predicted by the model (if the flow model cannot be validated, then ICDA is not feasible for the segment); and

(iii) Continually monitoring each ICDA region which contains a covered segment where internal corrosion has been identified by using techniques such as coupons or UT sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the ICDA region. At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7½ months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with § 192.933.

(A) Conduct excavations of, and detailed examinations at, locations downstream from where the electrolyte might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of § 192.478; or

(B) Assess the covered segment using ILI tools capable of detecting internal corrosion.

(5) *Other requirements*—The ICDA plan must also include the following:

(i) Criteria an operator will apply in making key decisions (*e.g.,* ICDA feasibility, definition of ICDA Regions and Sub-regions, conditions requiring excavation) in implementing each stage of the ICDA process;

(ii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of § 192.933 may be limited to covered segments.

■ 43. Section 192.929 is revised to read as follows:

§ 192.929 What are the requirements for using direct assessment for stress corrosion cracking (SCCDA)?

(a) *Definition.* Stress corrosion cracking direct assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

(b) *General requirements.* An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must develop and follow an SCCDA plan that meets all requirements and recommendations contained in NACE SP0204–2008 and that implements all four steps of the SCCDA process including pre-assessment, indirect inspection, detailed examination and post-assessment. As specified in NACE SP0204–2008, Section 1.1.7, SCCDA is complementary with other inspection methods such as in-line inspection (ILI) or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. In addition, the plan must provide for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment in accordance with NACE SP0204–2008, sections 3 and 4, and table 1. This process must also include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204–2008 indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204–2008, section 5.3, and must include, at minimum, all data listed in NACE SP0204–2008, table 2. Further, the following factors must be analyzed as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment such as soil temperature, moisture, the presence or generation of carbon dioxide, and/or Cathodic Protection (CP).

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments.

(iii) The effects of variations in applied CP such as overprotection, CP loss for extended periods, and high negative potentials.

(iv) The effects of coatings that shield CP when disbonded from the pipe.

(v) Other factors which affect the mechanistic properties associated with SCC including but not limited to historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.

(2) *Indirect inspection.* In addition to the requirements and recommendations of NACE SP0204–2008, section 4, the

plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using complementary measurement tools most appropriate for the pipeline segment based on the data gathering and integration step.

(3) *Direct examination.* In addition to the requirements and recommendations of NACE SP0204–2008, the plan's procedures for direct examination must provide for conducting a minimum of three direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur.

(4) *Remediation and mitigation.* If any indication of SCC is discovered in a segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Removing the pipe with SCC, remediating the pipe with a Type B sleeve, hydrostatic testing in accordance with (b)(4)(ii), below, or by grinding out the SCC defect and repairing the pipe. If grinding is used for repair, the repair procedure must include: Nondestructive testing for any remaining cracks or other defects; measuring remaining wall thickness; and the remaining strength of the pipe at the repair location must be determined using ASME/ANSI B31G or RSTRENG and must be sufficient to meet the design requirements of subpart C of this part. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.

(ii) Significant SCC must be mitigated using a hydrostatic testing program to a minimum test pressure equal to 105 percent of the specified minimum yield strength of the pipe for 30 minutes immediately followed by a pressure test in accordance with § 192.506, but not lower than 1.25 times MAOP. The test pressure for the entire sequence must be continuously maintained for at least 8 hours, in accordance with § 192.506 and must be above the minimum test factors in § 192.619(a)(2)(ii) or 192.620(a)(2)(ii), but not lower than 1.25 times maximum allowable operating pressure. Any test failures due to SCC must be repaired by replacement of the pipe segment, and the segment re-tested until the pipe passes the complete test without leakage. Pipe segments that have SCC present, but that pass the pressure test, may be repaired by grinding in accordance with paragraph (b)(4)(i) of this section.

(5) *Post assessment.* In addition to the requirements and recommendations of NACE SP0204–2008, sections 6.3, periodic reassessment, and 6.4, effectiveness of SCCDA, the operator's procedures for post assessment must include development of a reassessment plan based on the susceptibility of the operator's pipe to SCC as well as on the mechanistic behavior of identified cracking. Reassessment intervals must comply with § 192.939. Factors that must be considered include, but are not limited to:

(i) Evaluation of discovered crack clusters during the direct examination step in accordance with NACE RP0204–2008, sections 5.3.5.7, 5.4, and 5.5;

(ii) Conditions conducive to creation of the carbonate-bicarbonate environment;

(iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;

(iv) Operating temperature and pressure conditions including operating stress levels on the pipe;

(v) Cyclic loading conditions;

(vi) Mechanistic conditions that influence crack initiation and growth rates;

(vii) The effects of interacting crack clusters;

(viii) The presence of sulfides; and.

(ix) Disbonded coatings that shield CP from the pipe.

■ 44. In § 192.933, paragraphs (a)(1), (b), (d)(1) are revised and paragraphs (d)(2)(iii) through (vii) are added to read as follows:

§ 192.933 What actions must be taken to address integrity issues?

(a) * * *

(1) *Temporary pressure reduction.* If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, see § 192.7) or AGA Pipeline Research Council International, PR–3–805 (R–STRENG) (incorporated by reference, *see* § 192.7) to determine the safe operating pressure that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, or reduce the operating pressure to a level not exceeding 80 percent of the operating pressure at the time the condition was discovered. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607. An operator must notify PHMSA in accordance with § 192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through temporary reduction in operating pressure or other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

* * * * *

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period the operator must notify OPS, in accordance with § 192.949, and provide an expected date when adequate information will become available.

* * * * *

(d) * * *

(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) Calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly for any class location. Suitable

remaining strength calculation methods include ASME/ANSI B31G (incorporated by reference, *see* § 192.7), PRCI PR–3–805 (R–STRENG) (incorporated by reference, *see* § 192.7); or an alternative method of remaining strength calculation that will provide an equally conservative result. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.

(ii) A dent that has any indication of metal loss, cracking, or a stress riser.

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(iv) Metal loss greater than 80% of nominal wall regardless of dimensions.

(v) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency, or high frequency electric resistance welding or by electric flash welding.

(vi) Any indication of significant stress corrosion cracking (SCC).

(vii) Any indication of significant selective seam weld corrosion (SSWC).

(2) * * *.

(iii) A calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations.

(iv) An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.

(v) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.

(vi) A gouge or groove greater than 12.5% of nominal wall.

(vii) Any indication of crack or crack-like defect other than an immediate condition.

* * * * *

■ 45. In § 192.935, paragraphs (a), (b)(2), and (d)(3) are revised and paragraphs (f) and (g) are added to read as follows:

§ 192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* An operator must take additional measures beyond those already required by part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Such additional measures must be based on the risk analyses required by § 192.917, and must include, but are not limited to: Correction of the root causes of past incidents to prevent recurrence; establishing and implementing adequate operations and maintenance processes that could increase safety; establishing and deploying adequate resources for successful execution of preventive and mitigative measures; installing automatic shut-off valves or remote control valves; installing pressure transmitters on both sides of automatic shut-off valves and remote control valves that communicate with the pipeline control center; installing computerized monitoring and leak detection systems; replacing pipe segments with pipe of heavier wall thickness or higher strength; conducting additional right-of-way patrols; conducting hydrostatic tests in areas where material has quality issues or lost records; tests to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantiate MAOP evaluations including material property tests from removed pipe that is representative of the in-service pipeline; re-coating of damaged, poorly performing or disbonded coatings; applying additional depth-of-cover survey at roads, streams and rivers; remediating inadequate depth-of-cover; providing additional training to personnel on response procedures, conducting drills with local emergency responders; and implementing additional inspection and maintenance programs.

(b) * * *

(2) *Outside force damage.* If an operator determines that outside force (*e.g.,* earth movement, loading, longitudinal, or lateral forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, relocating the line, or geospatial, GIS, and deformation in-line inspections.

* * * * *

(d) * * *

(3) Perform semi-annual, instrumented leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where indirect assessments, *i.e.* indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent, are impractical).

* * * * *

(f) *Internal corrosion.* As an operator gains information about internal corrosion, it must enhance its internal corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to internal corrosion. At a minimum, as part of this enhancement, operators must—

(1) Monitor for, and mitigate the presence of, deleterious gas stream constituents.

(2) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and continuous gas quality monitoring equipment.

(3) At least once per quarter, use gas quality monitoring equipment that includes, but is not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and hydrogen sulfide sampling.

(4) Use cleaning pigs and sample accumulated liquids and solids, including tests for microbiologically induced corrosion.

(5) Use inhibitors when corrosive gas or corrosive liquids are present.

(6) Address potentially corrosive gas stream constituents as specified in § 192.478(a), where the volumes exceed these amounts over a 24-hour interval in the pipeline as follows:

(i) Limit carbon dioxide to three percent by volume;

(ii) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and

(iii) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas. If the hydrogen sulfide concentration is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.

(7) Review the program at least semi-annually based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.

(g) *External corrosion.* As an operator gains information about external corrosion, it must enhance its external corrosion management program, as required under subpart I of this part, with respect to a covered segment to

prevent and minimize the consequences of a release due to external corrosion. At a minimum, as part of this enhancement, operators must—

(1) Control electrical interference currents that can adversely affect cathodic protection as follows:

(i) As frequently as needed (such as when new or uprated high voltage alternating current power lines greater than or equal to 69 kVA or electrical substations are co-located near the pipeline), but not to exceed every seven years, perform the following:

(A) Conduct an interference survey (at times when voltages are at the highest values for a time period of at least 24-hours) to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;

(B) Analyze the results of the survey to identify locations where interference currents are greater than or equal to 20 Amps per meter squared; and

(C) Take any remedial action needed within six months after completing the survey to protect the pipeline segment from deleterious current. Remedial action means the implementation of measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. Any location with interference currents greater than 50 Amps per meter squared must be remediated. If any AC interference between 20 and 50 Amps per meter squared is not remediated, the operator must provide and document an engineering justification.

(2) Confirm the adequacy of external corrosion control through indirect assessment as follows:

(i) Periodically (as frequently as needed but at intervals not to exceed seven years) assess the adequacy of the cathodic protection through an indirect method such as close-interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG).

(ii) Remediate any damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBμv for ACVG) under section 4 of NACE RP0502–2008 (incorporated by reference, see § 192.7).

(iii) Integrate the results of the indirect assessment required under paragraph (g)(2)(i) of this section with the results of the most recent integrity assessment required by this subpart and promptly take any needed remedial actions no later than 6 months after assessment finding.

(iv) Perform periodic assessments as follows:

(A) Conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with integrity assessments under sections §§ 192.921 and 192.937 of this subpart.

(B) Locate pipe-to-soil test stations at half-mile intervals within each covered segment, ensuring at least one station is within each high consequence area, if practicable.

(C) Integrate the results with those of the baseline and periodic assessments for integrity done under sections §§ 192.921 and 192.937 of this subpart.

(3) Control external corrosion through cathodic protection as follows:

(i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete assessment and remedial action, as required in § 192.465(f), within 6 months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service and demonstrate that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and

(ii) Remediate insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline in accordance with paragraph (g)(3)(i) of this section, including use of indirect assessments or direct examination of the coating in areas of low CP readings unless the reason for the failed reading is determined to be a short to an adjacent foreign structure, rectifier connection or power input problem that can be remediated and restoration of adequate cathodic protection can be verified. The operator must confirm restoration of adequate corrosion control by a close interval survey on both sides of the affected test stations to the adjacent test stations.

■ 46. In § 192.937, paragraphs (b) and (c) are revised to read as follows:

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

* * * * *

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in § 192.917, which incorporates an analysis of updated pipeline design, construction, operation, maintenance, and integrity information. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in § 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§ 192.917), and decisions about remediation (§ 192.933). The evaluation must identify the threats specific to each covered segment, including interacting threats and the risk represented by these threats, and identify additional preventive and mitigative measures (§ 192.935) to avert or reduce risks.

(c) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917). An operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

(1) Internal inspection tool or tools capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment performed under paragraph (b) of this section to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing anomalies.

(2) Pressure test conducted in accordance with subpart J of this part.

An operator must use the test pressures specified in table 3 of section 5 of ASME/ANSI B31.8S to justify an extended reassessment interval in accordance with § 192.939. The use of pressure testing is appropriate for time dependent threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms and for manufacturing and related defect threats, including defective pipe and pipe seams.

(3) ''Spike'' hydrostatic pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for threats such as stress corrosion cracking, selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects.

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI). An operator must explicitly consider uncertainties in in situ direct examination results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, and usage unity chart plots or equivalent for determining uncertainties and verifying performance on the type defects being evaluated) in identifying and characterizing anomalies.

(5) Guided Wave Ultrasonic Testing (GWUT) conducted as described in Appendix F;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (c)(1) through (5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in § 192.925, 192.927, or 192.929;

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with § 192.949 and receive a ''no objection letter'' from the Associate Administrator of Pipeline Safety. An operator must also notify the appropriate State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(8) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with § 192.931.

■ 47. In § 192.939, the introductory text of paragraph (a) is revised to read as follows:

§ 192.939 What are the required reassessment intervals?

* * * * *

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven calendar years. Operators may request a six month extension of the seven-calendar year reassessment interval if the operator submits written notice to OPS, in accordance with § 192.949, with sufficient justification of the need for the extension. If an operator establishes a reassessment interval that is greater than seven calendar years, the operator must, within the seven-calendar year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with § 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

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■ 48. In § 192.941, paragraphs (b)(1) and the introductory text to (b)(2) are revised to read as follows:

§ 192.941 What is a low stress reassessment?

* * * * *

(b) * * *

(1) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an indirect assessment (*i.e.* indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) at least every seven years on the covered segment. An operator must use the results of each indirect assessment as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe where indirect assessments are impractical.* If an indirect assessment is impractical on the covered segment an operator must—

* * * * *

■ 49. Appendix A to part 192 is revised to read as follows:

Appendix A to Part 192—Records Retention Schedule for Transmission Pipelines

Appendix A summarizes the part 192 records retention requirements. As required by § 192.13(e), records must be readily retrievable and must be reliable, traceable, verifiable, and complete.

Code section	Section title	Summary of records requirement (**Note:** referenced code section specifies requirements. This summary provided for convenience only.)	Retention time
Subpart A—General			
§ 192.5(d)	Class locations	Records that demonstrate how an operator determined class locations and the actual class locations.	Life of pipeline.
§ 192.13(e)	What general requirements apply to pipelines regulated under this part?.	Records that demonstrate compliance with this part. At a minimum, operators must prepare and maintain the records specified in appendix A to part 192.	As specified in this appendix.

Code section	Section title	Summary of records requirement (**Note:** referenced code section specifies requirements. This summary provided for convenience only.)	Retention time
§ 192.14(b)	Conversion to service subject to this part.	Records of investigations, tests, repairs, replacements, and alterations made under the requirements of § 192.14(a).	Life of pipeline.
§ 192.16(d)	Customer notification	Records of a copy of the notice currently in use and evidence that notices have been sent to customers.	3 years.
Subpart B—Materials			
§ 192.67	Records: Materials and pipe	Records for steel pipe manufacturing tests, inspections, and attributes.	Life of pipeline.
Subpart C—Pipe Design			
§ 192.112	Additional design requirements for steel pipe using alternative maximum allowable operating pressure.	Records for alternative MAOP demonstrating compliance with this section.	Life of pipeline.
§ 192.127	Records: Pipe Design for External Loads and Internal Pressures.	Design records for external loads and internal pressure.	Life of pipeline.
Subpart D—Design of Pipeline Components			
§ 192.144	Qualifying metallic components	Records indicating manufacturer and pressure ratings of metallic components.	Life of pipeline.
§ 192.150	Passage of internal inspection devices	Records of each new transmission line replacement of pipe, valves, fittings, or other line component showing that the replacement is constructed to accommodate internal inspection devices as required by § 192.150.	Life of pipeline.
§ 192.153	Components fabricated by welding	Records of strength tests	Life of pipeline.
§ 192.205	Records: Pipeline components	Records documenting the manufacturing standard, tests, and pressure rating to which valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, tap connections, and other components were manufactured and tested in accordance with this subpart.	Life of pipeline.
Subpart E—Welding of Steel in Pipelines			
§ 192.225(b)	Welding procedures	Records of welding procedures, including results of qualifying procedure tests.	Life of pipeline.
§ 192.227(c)	Qualification of welders and welding operators.	Records demonstrating welder qualification	Life of pipeline.
§ 192.243(f)	Nondestructive testing	Records showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.	Life of pipeline.
Subpart F—Joining of Materials Other Than by Welding			
§ 192.283	Plastic pipe: Qualifying joining procedures.	Records of joining procedures, including results of qualifying procedure tests.	Life of pipeline.
§ 192.285(e)	Plastic pipe: Qualifying persons to make joints.	Records demonstrating plastic pipe joining qualifications.	Life of pipeline.
Subpart G—General Construction Requirements for Transmission Lines and Mains			
§ 192.303	Compliance with specifications or standards.	Records of written specifications or standards that apply to each transmission line or main.	Life of pipeline.
§ 192.305	Inspection: General	Transmission line or main inspections	Life of pipeline.
§ 192.307	Inspection of materials	Pipe and component materials inspections	Life of pipeline.
§ 192.319(d)	Installation of pipe in a ditch	Records documenting the coating assessment findings and repairs.	Life of pipeline.
§ 192.328	Additional construction requirements for steel pipe using alternative maximum allowable operating pressure.	Records for alternative MAOP demonstrating compliance with this section including: quality assurance, girth weld non-destructive examinations, depth of cover, initial strength testing (pressure tests and root cause analysis of failed pipe), and impacts of interference currents.	Life of pipeline.

Code section	Section title	Summary of records requirement (**Note:** referenced code section specifies requirements. This summary provided for convenience only.)	Retention time
		Subpart H—Customer Meters, Service Regulators, and Service Lines	
§ 192.383	Excess flow valve installation	Number of excess flow valves installed, as reported as part of annual report.	Life of pipeline.
		Subpart I—Requirements for Corrosion Control	
§ 192.452(a)	How does this subpart apply to converted pipelines and regulated onshore gathering lines?.	Records demonstrating compliance by the applicable deadlines.	Life of pipeline.
§ 192.459	Exposed buried pipe inspection	Records of examinations for evidence of external corrosion whenever any portion of a buried pipeline is exposed.	Life of pipeline.
§ 192.461	External corrosion control: Protective coating.	Records of protective coating type, coating installation and procedures, surveys, and remediation of coating defects.	Life of pipeline.
§ 192.465(a)	External corrosion control: Monitoring	Records of pipe to soil measurements	Life of pipeline.
§ 192.465(b)	External corrosion control: Monitoring—rectifiers.	Records of rectifier inspections	5 years.
§ 192.465(c)	External corrosion control: Monitoring—stray current/interference mitigation and critical interference bonds.	Records of inspections of each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection.	5 years.
§ 192.465(e)	External corrosion control: Monitoring—active corrosion zones.	Records of re-evaluation of cathodically unprotected pipelines.	Life of pipeline.
§ 192.467(d)	External corrosion control: Electrical isolation.	Records of inspection and electrical tests made to assure that electrical isolation is adequate.	Life of pipeline.
§ 192.473	External corrosion control: Interference currents.	Records of surveys, analysis, and remediation of interference currents.	Life of pipeline.
§ 192.475	Internal pipe inspection	Records demonstrating whenever any pipe is removed from a pipeline for any reason, the internal surface was inspected for evidence of corrosion.	Life of pipeline.
§ 192.476(d)	Internal corrosion control: Design and construction of transmission line.	Records demonstrating compliance with this section	Life of pipeline.
§ 192.477	Coupons or other means for monitoring internal corrosion.	Records demonstrating the effectiveness of each coupon or other means of monitoring procedures used to minimize internal corrosion.	Life of pipeline.
§ 192.478	Internal corrosion control: Onshore transmission monitoring and mitigation.	Records demonstrating compliance with this section for internal monitoring and mitigation program.	Life of pipeline.
§ 192.478(b)(3)	Gas and Liquid Samples	Records showing evaluation twice each calendar year of gas stream and liquid quality samples.	Life of pipeline.
§ 192.481(a)	Atmospheric corrosion control: Monitoring.	Records of inspection of each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion.	5 years.
§ 192.485(c)	Remedial measures: Transmission lines.	Pipe and material properties used in remaining strength calculations and remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records.	Life of pipeline.
§ 192.491(a) and (b)	Corrosion control records	Records or maps showing the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system.	Life of pipeline.
§ 192.491(c)	Corrosion control records	Records of each test, survey, or inspection required by subpart I in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist.	5 years.
		Records related to §§ 192.465(a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.	Life of pipeline.
		Subpart J—Test Requirements	
§ 192.517(a)	Records	Records of each test performed under §§ 192.505, 192.506, and 192.507.	Life of pipeline.
§ 192.517(b)	Records	Records of each test required by §§ 192.509, 192.511, and 192.513.	5 years.

Code section	Section title	Summary of records requirement (**Note:** referenced code section specifies requirements. This summary provided for convenience only.)	Retention time
Subpart K—Uprating			
§ 192.553(b)	General requirements	Records of each investigation required by subpart K, of all work performed, and of each pressure test conducted, in connection with uprating of a segment of pipeline.	Life of pipeline.
Subpart L—Operations			
§ 192.603(b)	General provisions	Records necessary to administer the procedures established under § 192.605 for operations, maintenance, and emergencies including class location and changes in §§ 192.5, 192.609, and 192.611.	Life of pipeline.
§ 192.605	Procedural manual for operations, maintenance, and emergencies.	Records for O&M Manual—review and update once per calendar year, not to exceed 15 months.	5 years.
§ 192.605	Procedural manual for operations, maintenance, and emergencies.	Records for Emergency Plan—review and update once per calendar year, not to exceed 15 months.	5 years.
§ 192.605	Procedural manual for operations, maintenance, and emergencies.	Records for Operator Qualification Plan—review and update once per calendar year, not to exceed 15 months.	5 years.
§ 192.605(b)(12)	Procedural manual for operations, maintenance, and emergencies.	Records for Control Room Management (CRM)—review and update once per calendar year, not to exceed 15 months.	5 years.
§ 192.605(c)	Procedural manual for operations, maintenance, and emergencies.	For gas transmission operators, a record of the abnormal operations.	Life of pipeline.
§ 192.607(c)	Verification of Pipeline Material: Onshore steel transmission pipelines.	Traceable, verifiable, and complete records that demonstrate and authenticate data and information regarding the properties outlined in § 192.607(c)(1) through (4).	Life of pipeline.
§ 192.609	Change in class location: Required study.	Records for class location studies required by this section.	Life of pipeline.
§ 192.611	Change in class location: Confirmation or revision of maximum allowable operating pressure.	Records for revisions of maximum allowable operating pressure due to class location changes to confirm to § 192.611.	Life of pipeline.
§ 192.612	Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.	Records of Underwater inspection in Gulf of Mexico—periodic, as indicated in operators O&M Manual.	5 years.
§ 192.613(a)	Continuing surveillance	Records of continuing surveillance findings	5 years.
§ 192.613(b)	Continuing surveillance	Records of remedial actions	Life of pipeline.
§ 192.613(c)(1)	Continuing surveillance	Records of inspections performed following extreme events.	5 years.
§ 192.613(c)(3)	Continuing surveillance	Records of remedial actions	Life of pipeline.
§ 192.614	Damage prevention program	Damage Prevention/One Call records	5 years (or as indicated by state one call, whichever is longer).
§ 192.614	Damage prevention program	Records of Damage Prevention meetings with Emergency Responder/Public Officials.	5 years.
§ 192.615	Emergency plans	Records of training	5 years.
§ 192.615	Emergency plans	Records of each review that procedures were effectively followed after each emergency.	5 years.
§ 192.616	Public awareness	Records showing Public Education Activities	5 years.
§ 192.617	Investigation of failures	Procedures for analyzing accidents and failures as described in § 192.617 to determine the causes of the failure and minimizing the possibility of a recurrence. Records of accident/failure reports.	Life of pipeline.
§ 192.619	Maximum allowable operating pressure: Steel or plastic pipelines.	Traceable, verifiable, and complete records that demonstrate and authenticate data and information regarding the maximum allowable operating pressures outlined in § 192.619(a) through (d).	Life of pipeline.
§ 192.620(c)(7)	Alternative maximum allowable operating pressure for certain steel pipelines.	Records demonstrating compliance with paragraphs § 192.620(b), (c)(6), and (d).	Life of pipeline.
§ 192.624(f)	Maximum allowable operating pressure verification: Onshore steel transmission pipelines.	Reliable, traceable, verifiable, and complete records of the investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions made under the requirements of § 192.624.	Life of pipeline.
§ 192.625	Odorization of gas	Records of Odorometer Readings—periodic, as indicated in operators O&M Manual.	5 years.

Code section	Section title	Summary of records requirement (**Note:** referenced code section specifies requirements. This summary provided for convenience only.)	Retention time
§ 192.631(a)	Control room management	Records of control room management procedures that implement the requirements of this section.	Life of pipeline.
§ 192.631(j)	Control room management	(1) Records that demonstrate compliance with the requirements of this section; and. (2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of a pipeline facility.	1 year, or the last 2 periodic tests or validations, whichever is longer.
Subpart M—Maintenance			
§ 192.703(c)	General	Records of hazardous and non-hazardous leaks	Life of pipeline.
§ 192.705	Transmission lines: Patrolling	Records of periodic right-of-way patrols—frequency dependent on class location.	5 years.
§ 192.706	Transmission lines: Leakage surveys	Records of periodic leakage surveys—frequency dependent on class location.	5 years.
§ 192.709(a)	Transmission lines: Record keeping	Records for the date, location, and description of each repair made to pipe (including pipe-to-pipe connections).	Life of pipeline.
§ 192.709(b) and (c)	Transmission lines: Record keeping	(b) Records of the date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. (c) A record of each patrol, survey, inspection, test, and repair required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.*	5 years.*
§ 192.710	Pipeline assessments	Records of pipeline assessments in class 3 or class 4 locations and moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (i.e., "smart pigs").	Life of pipeline.
§ 192.713(c)	Transmission lines: Permanent field repair of imperfections and damages.	Records of each repair made to transmission lines must be documented.	Life of pipeline.
§ 192.713(d)	Transmission lines: Permanent field repair of imperfections and damages.	Repair and remediation schedules, pressure reductions and remaining strength calculations must be documented.	Life of pipeline.
§ 192.731	Compressor stations: Inspection and testing of relief devices.	Records of inspections and tests of pressure relieving and other remote control shutdown devices.	5 years.
§ 192.736	Compressor stations: Gas detection	Records of inspections and tests of gas detection systems—periodic, as indicated in operators O&M Manual.	5 years.
§ 192.739	Pressure limiting and regulating stations: Inspection and testing.	Records of inspections and tests of pressure relief devices and pressure regulating stations and equipment.	5 years.
§ 192.743	Pressure limiting and regulating stations: Capacity of relief devices.	Records of capacity calculations or verifications for pressure relief devices (except rupture discs).	5 years.
§ 192.745	Valve maintenance: Transmission lines	Records of inspections of emergency valves	5 years.
§ 192.749	Vault maintenance	Records of inspections of vaults containing pressure regulating or pressure limiting equipment.	5 years.
Subpart N—Qualification of Pipeline Personnel			
§ 192.807	Operator qualification recordkeeping	Records that demonstrate compliance with subpart N of this part Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task.** Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years..	5 years.**
Subpart O—Gas Transmission Integrity Management			
§ 192.947	Integrity management	Records that demonstrate compliance with all of the requirements of subpart O of this part.	Life of pipeline.

■ 50. Appendix D to part 192 is revised to read as follows:

Appendix D to Part 192—Criteria for Cathodic Protection and Determination of Measurements

I. *Criteria for cathodic protection*—

A. *Steel, cast iron, and ductile iron structures.*

(1) A negative (cathodic) voltage across the structure electrolyte boundary of at least 0.85 volt, with reference to a saturated copper-copper sulfate reference electrode, often referred to as a half cell. Determination of this voltage must be made in accordance with sections II and IV of this appendix.

(2) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

B. *Aluminum structures.*

(1) Except as provided in paragraphs B(2) and (3) of this section, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(2) Notwithstanding the minimum criteria in paragraph B(1) of this section, if aluminum is cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate reference electrode, in accordance with section II of this appendix, the aluminum may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(3) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. *Copper structures.* A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. *Metals of different anodic potentials.* A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs B(2) and (3) of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement.* Structure-to-electrolyte potential measurements must be made utilizing measurement techniques that will minimize voltage (IR) drops other than those across the structure electrolyte boundary. All voltage (IR) drops other than those across the structure electrolyte boundary will be differentiated, such that the resulting measurement accurately reflects the structure-to-electrolyte potential.

III. *Determination of polarization voltage shift.* The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs often referred to as an instant off potential. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(2), B(1), and C of section I of this appendix.

IV. *Reference electrodes (half cells).*

A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate reference electrode contacting the electrolyte.

B. Other standard reference electrodes may be substituted for the saturated copper-copper sulfate electrode. Two commonly used reference electrodes are listed below along with their voltage equivalent to −0.85 volt as referred to a saturated copper-copper sulfate reference electrode:

(1) Saturated KCL calomel half cell: −0.78 volt.

(2) Silver-silver chloride reference electrode used in sea water: −0.80 volt.

C. In addition to the standard reference electrode, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate reference electrode if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate reference electrode is established.

■ 51. In appendix E, Tables E.II.1 and E.II.3 are revised to read as follows:

Appendix E to Part 192—Guidance on Determining High Consequence Areas and on Carrying out Requirements in the Integrity Management Rule

* * * * *

II. Guidance on Assessment Methods and Additional Preventive and Mitigative Measures for Transmission Pipelines

* * * * *

TABLE E.II.1—PREVENTIVE AND MITIGATIVE MEASURES FOR TRANSMISSION PIPELINES OPERATING BELOW 30% SMYS NOT IN AN HCA BUT IN A CLASS 3 OR CLASS 4 LOCATION

(Column 1) Threat	Existing part 192 requirements		(Column 4) Additional (to part 192 requirements) preventive and mitigative measures
	(Column 2) Primary	(Column 3) Secondary	
External Corrosion	455—(Gen. Post 1971), 457—(Gen. Pre—1971).	603—(Gen Operation)	For Cathodically Protected Transmission Pipeline:
	459—(Examination), 461—(Ext. coating).	613—(Surveillance)	• Perform semi-annual leak surveys.
	463—(CP), 465—(Monitoring).		For Unprotected Transmission Pipelines or for Cathodically Protected Pipe where indirect assessments (*i.e.,* indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) are impractical:
	467—(Elect isolation), 469—Test stations).		
	471—(Test leads), 473—(Interference).		
	479—(Atmospheric), 481—(Atmospheric).		
	485—(Remedial), 705—(Patrol).		
	706— (Leak survey), 711—(Repair—gen.).		
	717—(Repair—perm.)		• Perform quarterly leak surveys.
Internal Corrosion	475—(Gen IC), 477—(IC monitoring).	53(a)—(Materials)	Perform semi-annual leak surveys.

TABLE E.II.1—PREVENTIVE AND MITIGATIVE MEASURES FOR TRANSMISSION PIPELINES OPERATING BELOW 30% SMYS NOT IN AN HCA BUT IN A CLASS 3 OR CLASS 4 LOCATION—Continued

(Column 1) Threat	Existing part 192 requirements		(Column 4) Additional (to part 192 requirements) preventive and mitigative measures
	(Column 2) Primary	(Column 3) Secondary	
	485—(Remedial), 705—(Patrol).	603—(Gen Oper'n).	
	706—(Leak survey), 711 (Repair—gen.).	613—(Surveillance).	
	717—(Repair—perm.).		
3rd Party Damage	103—(Gen. Design), 111—(Design factor).		• Participation in state one-call system.
	317—(Hazard prot), 327—(Cover).	615—(Emerg. Plan)	• Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work.
	614—(Dam. Prevent), 616—(Public education).		AND
	705—(Patrol), 707—(Line markers).		• Either monitoring of excavations near operator's transmission pipelines in class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.
	711—(Repair—gen.), 717—(Repair—perm.).		

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TABLE E.II.3—PREVENTIVE AND MITIGATIVE MEASURES ADDRESSING TIME DEPENDENT AND INDEPENDENT THREATS FOR TRANSMISSION PIPELINES THAT OPERATE BELOW 30% SMYS, IN HCAS

Threat	Existing part 192 requirements		Additional (to part 192 requirements) preventive and mitigative measures
	Primary	Secondary	
External Corrosion	455—(Gen. Post 1971)		*For Cathodically Protected Transmission Pipelines*
	457—(Gen. Pre-1971)		• Perform an indirect assessment (i.e. indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) at least every 7 years. Results are to be utilized as part of an overall evaluation of the CP system and corrosion threat for the covered segment. Evaluation shall include consideration of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
	459—(Examination).		
	461—(Ext. coating).		
	463—(CP).		
	465—(Monitoring)	603—(Gen. Operation).	
	467—(Elect isolation)	613—(Surveillance).	
	469—(Test stations).		
	471—(Test leads)		*For Unprotected Transmission. Pipelines or for Cathodically Protected Pipe where Indirect Assessments are Impracticable*
	473—(Interference).		
	479—(Atmospheric)		• Conduct quarterly leak surveys AND
	481—(Atmospheric)		• Every 1½ years, determine areas of active corrosion by evaluation of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
	485—(Remedial).		
	705—(Patrol).		
	706—(Leak survey).		
	711—(Repair—gen.).		
	717—(Repair—perm.).		
Internal Corrosion	475—(Gen. IC)		• Obtain and review gas analysis data each calendar year for corrosive agents from transmission pipelines in HCA,
	477—(IC monitoring)		• Periodic testing of fluid removed from pipelines. Specifically, once each year from each storage field that may affect transmission pipelines in HCA, AND
	485—(Remedial)	53(a)—(Materials)	• At least every 7 years, integrate data obtained with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records.
	705—(Patrol)	603—(Gen. Oper.).	
	706—(Leak survey)	613—(Surveil.).	
	711—(Repair—gen.).		

TABLE E.II.3—PREVENTIVE AND MITIGATIVE MEASURES ADDRESSING TIME DEPENDENT AND INDEPENDENT THREATS FOR TRANSMISSION PIPELINES THAT OPERATE BELOW 30% SMYS, IN HCAS—Continued

Threat	Existing part 192 requirements		Additional (to part 192 requirements) preventive and mitigative measures
	Primary	Secondary	
3rd Party Damage	717—(Repair—perm.). 103—(Gen. Design) 111—(Design factor) 317—(Hazard prot.) 327—(Cover). 614—(Dam. Prevent). 616—(Public educat.). 705—(Patrol). 707—(Line markers). 711—(Repair—gen.). 717—(Repair—perm.).	615— (Emerg. Plan)	• Participation in state one-call system, • Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND • Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in HCAs or class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.

■ 52. Appendix F to part 192 is added to read as follows:

Appendix F to Part 192—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

This appendix defines criteria which must be properly implemented for use of Guided Wave Ultrasonic Testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered ''other technology'' as described by §§ 192.710(c)(7), 192.921(a)(7), and 192.937(c)(7), for which OPS must be notified 180 days prior to use in accordance with § 192.921(a)(7) or 192.937(c)(7). GWUT in the ''Go-No Go'' mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of 5% of cross sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested or replaced prior to completing the integrity assessment on the cased carrier pipe.

I. *Equipment and software: Generation.* The equipment and the computer software used are critical to the success of the inspection. Guided Ultrasonics LTD (GUL) Wavemaker G3 or G4 with software version 3 or higher, or equipment and software with equivalent capabilities and sensitivities, must be used.

II. *Inspection range.* The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.

III. *Complete pipe inspection.* To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.

IV. *Sensitivity.*

A. The detection sensitivity threshold determines the ability to identify a cross sectional change. The maximum threshold sensitivity cannot be greater than 5% of the cross sectional area (CSA).

B. The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented.

C. All defect indications in the ''Go-No Go'' mode above the 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.

V. *Wave frequency.* Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.

VI. *Signal or wave type: Torsional and longitudinal.* Both torsional and longitudinal waves must be used and use must be documented.

VII. *Distance amplitude correction (DAC) curve and weld calibration.*

A. The Distance Amplitude Correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection.

B. DAC curves provide a means for evaluating the cross sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

VIII. *Dead zone.* The dead zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the dead zone is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

IX. *Near field effects.* The near field is the region beyond the dead zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

X. *Coating type.*

A. Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance.

B. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For

example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the cased pipe, then another type of assessment method must be utilized.

XI. *End seal.* Operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator's corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.

XII. *Weld calibration to set DAC curve.* Accessible welds, along or outside the pipe segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used if welds along the pipe segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Alternative means of calibration can be used if justified by sound engineering analysis and evaluation.

XIII. *Validation of operator training.*

A. There is no industry standard for qualifying GWUT service providers. Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT equipment operators which includes training for:

(1) Equipment operation;
(2) Field data collection; and
(3) Data interpretation on cased and buried pipe.

B. Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment.

C. A Senior level GWUT equipment operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A senior level GWUT equipment operator must have additional training and experience, including but not limited to training specific to cased and buried pipe, with a quality control program which conforms to section 12 of ASME B31.8S.

D. Training and experience minimums for senior level GWUT equipment operators:

(1) Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe
(2) Training, qualification and experience in testing procedures and frequency determination
(3) Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)
(4) Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XIV. *Equipment: Traceable from vendor to inspection company.* The operator must maintain documentation of the version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., in the report.

XV. *Calibration onsite.* The GWUT equipment must be calibrated for performance in accordance with the manufacturer's requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated. If on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the equipment can be restored to manufacturer's specifications.

XVI. *Use on shorted casings (direct or electrolytic).* GWUT may not be used to assess shorted casings. GWUT operators must have operations and maintenance procedures (see § 192.605) to address the effect of shorted casings on the GWUT signal. The equipment operator must clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures. All shorted casings found while conducting GWUT inspections must be addressed by the operator's standard operating procedures.

XVII. *Direct examination of all indications above the detection sensitivity threshold.*

The use of GWUT in the ''Go-No Go'' mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe. If this cannot be accomplished then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

XVIII. *Timing of direct examination of all indications above the detection sensitivity threshold.* Operators must either replace or conduct direct examinations of all indications identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.

Required response to GWUT indications

GWUT Criterion	Operating pressure less than or equal to 30% SMYS	Operating pressure over 30 and less than or equal to 50% SMYS	Operating pressure over 50% SMYS
Over the detection sensitivity threshold (maximum of 5% CSA).	Replace or direct examination within 12 months, and instrumented leak survey once every 30 calendar days.	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and maintain MAOP below the operating pressure at time of discovery.	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and reduce MAOP to 80% of operating pressure at time of discovery.

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Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

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Preliminary Regulatory Impact Assessment

Notice of Proposed Rulemaking - Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines

Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
U. S. Department of Transportation

EXECUTIVE SUMMARY

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is proposing to change the Federal pipeline safety regulations in 49 CFR Parts 191 and 192, which cover the transportation of gas by transmission and gathering pipelines. Specifically, PHMSA is proposing to issue new regulations and revise existing regulations to address the following topic areas:

1. Integrity Assessment and Remediation for Segments Outside High Consequence Areas (HCAs) and to re-establish Maximum Allowable Operating Pressure (MAOP)
2. Integrity Management Program Process Clarifications
3. Management of Change
4. Corrosion Control
5. Inspection of Pipelines Following Extreme Events
6. MAOP Exceedance Reports and Records Verification
7. Launcher/Receiver Pressure Relief
8. Expansion of Regulated Gas Gathering Pipelines

This Regulatory Impact Analysis (RIA) provides PHMSA's analysis of the impact of the above topic areas implemented over a 15-year period. Topic Areas 1 through 7 apply to gas transmission pipelines. Topic Area 8 applies to gas gathering pipelines.

ES.1 PROBLEM STATEMENT

The purpose of the proposed rule is to increase the safety of gas pipeline operations. The proposed requirements address safety issues associated with statutory mandates, National Transportation Safety Board (NTSB) recommendations, and Government Accountability Office (GAO) recommendations:

- Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (PL 112-90)
  - Section 5(e) – Allow periodic reassessments to be extended for an additional 6 months if the operator submits sufficient justification.
  - Section 5(a) and (f) – Evaluate whether integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas and, if justified, issue regulations.
  - Section 21 – Regulation of Gas (and Hazardous Liquid) Gathering Lines
  - Section 23 – Regulations to confirm the MAOP of certain pipe with insufficient records and test the material strength of previously untested natural gas transmission pipelines in HCAs
  - Section 29 – Consider seismicity when evaluating pipeline threats
- Government Accountability Office Report GAO-14-667, Department of Transportation Is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to Improve Pipeline Safety, August 2014.
  - The GAO recommended that rulemaking be pursued for gathering lines that addresses the risks of larger-diameter, higher-pressure gathering lines,

including subjecting such pipelines to emergency response planning requirements.

- NTSB Recommendations
  - P-11-14 – Recommendation to PHMSA to amend 49 CFR 192.619 to delete exception and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.
  - P-11-15 – Recommendation to PHMSA to amend 49 CFR Part 192 so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP.
  - P-11-17 – Recommendation to PHMSA to require all natural gas transmission pipelines be configured to accommodate in-line inspection tools, with priority given to older pipelines.
  - P-11-19 – Recommendation to PHMSA to develop and implement standards for integrity management and other performance-based safety programs that require operators to regularly assess the effectiveness of their programs.
  - P-12-3 – Recommendation to PHMSA to revise 49 CFR §195.452 to address engineering assessment, assessment methods, excavation criteria, pressure restriction limits, and acceptable methods for determining crack growth for crack defects in steel pipe.
  - P-14-1 – Recommendation to PHMSA to revise 49 CFR §192.903, Subpart O, to add principal arterial roadways to the list of “identified sites” that establish a High Consequence Area.

These statutory mandates and recommendations stem from a number of high profile and high consequence gas transmission and gathering pipeline incidents and changes in the industry since the establishment of existing regulatory requirements.

ES.2 BASELINE FOR THE ANALYSIS

Current regulations require gas transmission pipeline operators to establish the maximum allowable operating pressure (MAOP) by pressure testing the pipe, with some exemptions, and maintain records documenting the material strength of the pipe. Current regulations require operators of gas transmission pipelines in high consequence areas (HCAs) to assess pipeline integrity (integrity management) every seven years. Operators conduct these assessments through pressure testing, inline inspection, and other inspection techniques. Operators also assess some percentage of pipelines located outside of HCAs, either in conjunction with assessments of HCA pipe or for other reasons. Operators report to PHMSA on pipeline mileage, material documentation records, integrity assessment mileage and methods, incidents that meet a threshold for reporting, and other infrastructure characteristics; these data underlie the analysis of the incremental impact of the proposed rule.

Current regulations apply to only a subset of gas gathering pipeline operations. As a result, PHMSA does not have data on the unregulated portion of this sector. Some operators of gas transmission and existing regulated gas gathering lines may have unregulated gathering lines. These operators may already have many of the operational programs and processes in place. These considerations also underlie the analysis of the incremental impact of the proposed rule.

From 2003 to 2015, there were approximately 1,200 incidents on gas transmission pipelines from all causes, one-third of which were from causes detectable by modern integrity assessment methods. **Table ES-1** summarizes monetized consequences from these incidents, including the estimated monetary value of fatalities and injuries ("value of a statistical life"), property damage, and other costs. Table ES-1 also shows monetized consequences from corrosion and excavation damage incidents in certain locations; these incidents may be similar to damages from Type A, Area 2 gas gathering lines proposed to be regulated.

Table ES-1. Historical Consequences of Onshore Gas Transmission Incidents (2003-2015; Millions 2015$)

Category	Death[1]	Serious Injury[2]	Other Costs of Incident[3]	Evacuation[4]	Total
All causes	$216.2	$125.3	$678.6	$21.1	1,041.3
Causes detectable by integrity assessment	$84.6	$59.2	$593.2	$5.6	$683.4
Corrosion and excavation damage[5]	$84.6	$19.7	$56.1	$5.6	$166.1

Source: Based on PHMSA Incident Report data
1. Value based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Value based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Includes all costs reported by the operator including estimated cost of public and non-operator private property damage. Excludes operator property damage and repair costs which may result in underestimating avoided consequences.
4. Value based on estimated $1,500 per person evacuation cost.
5. Reflects Class 1 and Class 2 locations.

In addition, between 2010 and 2014, gas transmission incidents resulted in an average release of 20,489 thousand cubic feet of natural gas. Natural gas primarily comprises methane, a greenhouse gas (GHG).

ES.3 ASSESSMENT OF REGULATORY IMPACT

Operators report gas transmission pipeline mileage and characteristics annually, and information on incidents involving the pipe that meet certain characteristics. PHMSA used these publically available data to estimate affected mileage subject to the proposed rule. Only a small portion of gas gathering pipelines are currently subject to reporting. Thus, much less data is available on this sector.

Relative to the baseline for the analysis, the proposed requirements in Topic Area 1 will result in integrity verification of previously untested pipe and pipe for which operator records are inadequate, and assessments similar to current requirements for HCA pipe for some pipe in moderate consequence areas (MCAs). Operators will comply through a combination of pressure testing, inline inspection (ILI), including upgrades to accommodate ILI, and direct assessment of approximately 16,600 miles of onshore gas transmission pipeline (**Table ES-2**). The affected mileage represents approximately five percent of total onshore gas transmission mileage. The proposal also provides an alternative to current requirements in cases of inadequate records that does not involve cut out and replacement of pipe.

Table ES-2. Summary of Estimated Mileage Impacted by Proposed Integrity Verification and Assessment Requirements, Topic Area 1	
Category	**Miles**
Re-establish MAOP: HCA > 30% SMYS	909
Re-establish MAOP: inadequate records	4,363
Integrity Assessment: MCA	7,379
Re-establish MAOP: HCA 20-30% SMYS; non-HCA Class 3 and 4; MCA Class 1 and 2	2,817
Total	**15,468**

HCA = high consequence area
MAOP = maximum allowable operating pressure
MCA = moderate consequence area
SMYS = specified minimum yield strength
Source: Analysis of PHMSA 2014 Annual Report data, pipeline and roadway maps, and PHMSA's best professional judgment as detailed in body of this report

Topic Areas 2 through 7 also apply to gas transmission pipeline and include process modifications and clarifications, more timely repair of defects, corrosion control, inspections, and other safety provisions, some of which operators already implement. **Table ES-3** summarizes the estimated affected mileages.

Table ES-3. Summary of Estimated Impact, Topic Areas 2 through 7		
Topic Area	**Topic Area Description**	**Estimated Impact**
2	More timely repairs	2,407 HCA miles[1]
3	Management of change	70 operators[2]
4	Corrosion control	See note 3
5	Inspection following extreme events	1,017 operators[4]
6	MAOP records	1,440 reports and 10-20 annually[5]
7	Launcher/receiver pressure relief	10 launchers/receivers

HCA = high consequence area
MAOP = maximum allowable operating pressure
NA = not applicable (no impact due to current compliance)
1. Average assessed per year. Represents mileage not included under Topic Area 1.
2. Based on best professional judgment.
3. Small portion of mileage estimated to be out of compliance for various requirements; interference surveys estimated to be needed for 2,711 miles.
4. Source: 2014 Gas Transmission Annual Reports
5. Based on a prestatutory baseline; operators are in compliance with the initial requirement.

Topic Area 8 will result in reporting on an estimated 344,000 miles of currently unregulated gas gathering pipeline infrastructure, and operators of an estimated 69,000 of these miles will also have to implement corrosion control and other safety measures (**Table ES-4**).

Table ES-4. Summary of Estimated Impact, Topic Area 8	
Proposed Requirements	**Estimated Mileage**
Corrosion control and safety measures: unregulated gas gathering lines >8" in diameter and operating in Class 1 at >20% specified minimum yield strength	68,749
Reporting: unregulated gas gathering lines	344,086

Table ES-4. Summary of Estimated Impact, Topic Area 8	
Proposed Requirements	**Estimated Mileage**
Source: Based on estimate from Amy Emmert, Policy Advisor, Upstream and Industry Operations, American Petroleum Institute, Re: Pipeline Safety: Safety of Gas Transmission Pipelines (Docket No. PHMSA-2011-0023), October 23, 2012, representing data from 45 operators, and assuming these operators represent 70% of the total, based on PHMSA best professional judgment.	

These actions will reduce the risk of gas transmission and gathering pipeline incidents, resulting in avoided property damage, death and injury, emergency responses and evacuations (see Table ES-3), and greenhouse gas emissions.

ES.4 ESTIMATION OF COSTS AND BENEFITS

Incremental costs of the proposed rule include costs associated with integrity assessments (pressure testing, inline inspection, upgrading to accommodate inline inspection, and direct assessment); GHG emissions associated with those assessments; corrosion control monitoring and surveys; process and program development; and reporting on previously unreported pipelines. PHMSA used per mile unit cost estimates for the assessment and testing components, and applied the costs using annual report data on pipeline characteristics and historical assessment methods. PHMSA estimated costs of lost gas by calculating lost volume and using the current gas price and the climate change effects by multiplying the volume by estimates of the social cost of methane (SCM). PHMSA estimated programmatic and reporting costs based on labor hours and labor costs.

To estimate the reductions in risks from implementing the safety provisions, PHMSA estimated defect discovery rates and the percent that would otherwise result in an incident (Topic Area 1). PHMSA also matched resulting incident rates to those from pipeline infrastructure currently subject to similar requirements to the extent feasible (Topic Area 8). For the remaining topic areas, PHMSA used best professional judgment for illustration or performed a break-even analysis.[1] **Table ES-5** summarizes the estimates of incidents averted by Topic Area.

Table ES-5. Summary of Estimated Incidents Averted[1]

Estimate	Topic Area						
	1	3	4	5	7	8	Total
Annual	5-15	1	7	1	0	19	33-43
Total (15 years)	74-221	15	108	8	1	271	477-624

Note: detail may not add to total due to independent rounding.
n.e. = not estimated
1. Topic Areas 2 and 6 not estimated.

For example, during 2003–2015, an average of 31 assessment-preventable incidents occurred each year on all onshore gas transmission pipeline mileage (range is 26 – 44). As shown in Table ES-5, the analysis of benefits of proposed requirements in Topic Area 1, which addresses assessment-preventable incidents on the estimated mileage shown in Table

[1] In many cases throughout this RIA, PHMSA lacked direct data or evidence on the values of parameters used in the analysis. In these cases, PHMSA relied on its experts' best professional judgment of the likely values. We seek comment, especially supported by accompanying data, on the accuracy of this judgment.

ES-2, is based on an estimate of averting 5 to15 such incidents annually. Absent adoption of the proposed rule, the number of incidents could exceed past numbers due to factors such as aging pipeline; however, such projections are speculative.

To value these avoided incidents, PHMSA used average consequences of incidents in similarly located pipelines based on the affected mileage which varies by Topic Area (i.e., avoided costs. PHMSA updated property damages to current dollars and used standard departmental methods for monetizing avoided injuries and fatalities based on the value of a statistical life. PHMSA valued evacuations by multiplying the number of persons evacuated by an estimate of per person evacuation cost (approximately $1,500).

To estimate the costs of GHG emissions associated with avoided incidents, PHMSA used data on releases per incident and estimates of the SCM as well as the social cost of carbon (SCC; due to combustion of gas).

ES.5 COSTS AND BENEFITS OF THE PROPOSED RULE

Table ES-6 summarizes the average annual present value benefits and costs using 7% and 3% discount rates, respectively. Topic Area 1 accounts for the majority of the benefits and costs. The majority of Topic Area 1 benefits reflect cost savings from material verification (processes to determine MAOP for segments for which records are inadequate) under the proposed rule compared to existing regulations; the range in these benefits reflects different effectiveness assumptions for estimating safety benefits. Costs reflect primarily integrity verification and assessment costs (pressure tests, inline inspection, and direct assessments). The proposed gas gathering regulations under Topic Area 8 account for the next largest portion of benefits and costs. Costs and benefits under Topic Area 8 primarily reflect safety provisions and associated risk reductions on previously unregulated lines.

Table ES-6. Summary of Present Value Average Annual Benefits and Costs[1] (Millions; 2015$)

Topic Area	7% Discount Rate		3% Discount Rate	
	Benefits	Costs	Benefits	Costs
1	$196.9 -$230.5	$17.8	$247.8 -$288.6	$22.0
2	n.e.[2]	$2.2	n.e.[2]	$1.3
3	$1.1	$0.7	$1.2	$0.8
4	$5.5	$6.3	$5.9	$7.9
5	$0.3	$0.1	$0.3	$0.1
6	n.e.	$0.2	n.e.	$0.2
7	$0.4	$0.0	$0.6	$0.0
8	$11.3	$12.6	$14.2	$15.1
Total	**$215.6 -$249.2**	**$39.8**	**$270.0 -$310.8**	**$47.4**

n.e. = not estimated
1. Total present value over 15-year study period divided by 15. Additional costs to states estimated not to exceed $1.5 million per year. Range of benefits reflects range in estimated defect failure rates.
2. Break even value of benefits, based on the average consequences for incidents in high consequence areas, would equate to approximately one incident averted over the 15-year study period.

Table ES-7 summarizes costs and benefits by subtopic within Topic Area 1.

Table ES-7. Summary of Average Annual Present Value Benefits and Costs for Topic Area 1 (Millions 2015$)[1]				
Subtopic	**Average Annual Benefits (7%)**	**Average Annual Costs (7%)**	**Average Annual Benefits (3%)**	**Average Annual Costs (3%)**
MAOP verification for segments within HCA	$3.6 -$8.9	$0.5	$4.5 -$11.1	$0.6
MAOP verification for segments with inadequate records within HCA and Class 3 and Class 4	$188 -$204.7	$8.0	$237 -$257.7	$9.8
Integrity assessments for segments within MCA in Class 3 and Class 4, and Class 1 and Class 2 (piggable)	$3 -$9.6	$6.3	$3.4 -$11	$7.9
MAOP verification for segments within HCA(20%-30% SMYS) and MCA (Class 3 and Class 4, and Class 1 and Class 2 piggable)	$2.4 -$7.3	$3.0	$2.9 -$8.9	$3.6
Total	**$196.9 -$230.5**	**$17.8**	**$247.8 -$288.6**	**$22.0**

HCA = high consequence area
MAOP = maximum allowable operating pressure
MCA = moderate consequence area
SMYS = specified minimum yield strength
1. Total present value over 15-year study period divided by 15.

Tables ES-8 and **ES-9** show the breakdown of benefits for each topic area by category at 7% and 3% discount rates, respectively.

ES-8. Summary of Average Annual Present Value Benefits, 7% Discount Rate (Millions 2015$)[1]				
Topic Area	**Safety**	**Cost Savings[2]**	**Climate[3]**	**Total**
1	$16.4 -$44.5[4]	$177.8	$2.7 -$8.2	$196.9 -$230.5
2	n.e.	n.e.	n.e.	n.e.
3	$0.5	$0.0	$0.6	$1.1
4	$1.6	$0.0	$4.0	$5.5
5	$0.0	$0.0	$0.3	$0.3
6	n.e.	n.e.	n.e.	n.e.
7	$0.4	$0.0	$0.0	$0.4
8	$9.7	$0.0	$1.6	$11.3
Total	**$28.6 -$56.7**	**$177.8**	**$9.2 -$14.62**	**$215.6 -$249.2**

n.e. = not estimated
1. Total present value over 15-year study period divided by 15.
2. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods.
3. Using 3% discounted values. TA 1 includes range for uncertainty.
4. Range reflects uncertainty in incidents averted rates.

Table ES-9. Summary of Average Annual Present Value Benefits, 3% Discount Rate (Millions 2015$)				
Topic Area	Safety	Cost Savings[1]	Climate[2]	Total
1	$20.6 -$56.1[3]	$224.4	$2.7 -$8.2	$247.8 -$288.6
2	n.e.	n.e.	n.e.	n.e.
3	$0.7	$0.0	$0.6	$1.2
4	$2.0	$0.0	$4.0	$5.9
5	$0.0	$0.0	$0.3	$0.3
6	n.e.	n.e.	n.e.	n.e.
7	$0.5	$0.0	$0.0	$0.6
8	$12.5	$0.0	$1.6	$14.2
Total	**$36.4 -$71.8**	**$224.4**	**$9.2 -$14.62**	**$270.0 -$310.8**

n.e. = not estimated
1. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods.
2. Using 3% discounted values. TA 1 includes range for uncertainty in incidents averted rates.
3. Range reflects uncertainty in incidents averted rates.

For the seven percent discount rate scenario, approximately 13 to 23 percent of benefits are due to safety benefits from incidents averted, 71 to 82 percent represent cost savings from MAOP verification in Topic Area 1, and 4 to 6 percent are attributable to reductions in GHG emissions. PHMSA estimated a net annual reduction of 931 metric tons of carbon dioxide and 4,600 metric tons of methane, a powerful greenhouse gas (**Table ES-10**).

ES-10. Net Average Annual Reduction in Greenhouse Gas Emissions[1]				
	Low Estimate		High Estimate	
Change in Emissions	MT CH_4[2]	MT $C0_2$	MT CH_4[2]	MT $C0_2$
Averted due to reduced incidents	5,864	968	9,332	1,501
Increased from compliance actions	-1,228	-44	-1,228	-44
Net reduction	4,636	924	8,104	1,457

MT= Metric ton
CH4= Methane, the primary component of natural gas
C02= Carbon Dioxide, marginal component of natural gas and product of methane combustion
1. Range reflects uncertainty in assessment effectiveness.
2. Converted based on one thousand cubic feet of methane = 0.0189 MT.

Based on estimated costs to states not exceeding $1.5 million per year, PHMSA determined that the rule would not impose annual expenditures by states in excess of the criteria in the Unfunded Mandates Reform Act. An Initial Regulatory Flexibility Analysis is in the docket for the rulemaking discusses small entity concerns.

ES.6 LIMITATIONS AND UNCERTAINTIES

There is substantial uncertainty in several parameters underlying the analysis including affected mileage, unit costs, effectiveness, and value of avoiding incidents. With respect to the affected mileage, commitments to expand assessment and repair programs beyond HCAs have already been made by the industry in PHMSA's workshops and in response to

the ANPRM dated August 25, 2011 (76 FR 53086). These commitments have the effect of reducing the compliance costs and the benefits associated with the proposed rule.

Also, in estimating costs and avoided risks of incidents, PHMSA relied on existing experience which reflects primarily assessment in HCAs. Extrapolation of this experience could overstate costs in MCAs due to the lower density of development. There is also uncertainty regarding the effectiveness of the proposal to reduce the risks of incidents. This is in part due to uncertainty in the estimates of defect discovery rates and the estimated percentages of defects that would result in an incident. In addition, there is no data on the extent of mileage that would meet the definition of an MCA.

Costs could also increase or decrease over time due to a variety of factors including technological improvement, changes in industry structure, and changes in prices. In particular, PHMSA expects ongoing development of new inline integrity assessment technologies to reduce the cost of ILI and to allow line segments that are currently unpiggable using conventional technology to use ILI without significant upgrade or replacement of the segment. A reduction in these assessment costs over time would further increase the net benefit of the proposed rule.

The benefits of reducing risks represent consequences from incidents reported by pipeline operators which do not include all consequences associated with incidents. Operators submit their casualty and direct loss/damage estimates only which may undervalue the impact of all consequences since other consequential costs, including indirect costs, to operators, other stakeholders, or society are not included. The inclusion of these unreported consequential costs of incidents would increase the estimated safety benefits associated with the proposed rule. The averages of reported consequences of past incidents could under- or overstate future consequences.

ES.7 ALTERNATIVES EVALUATED

PHMSA also evaluated a number of alternatives to the proposed rule. **Table ES-11** summarizes provides a summary of this analysis.

Table ES-11. Summary of Alternatives Analysis

Topic Area	Alternative
1	More stringent MCA criteria (1 building in PIR) and expansion of testing to re-establish MAOP
1	More limited MCA scope (excluding less than 8” diameter pipe)
1	Expand scope of HCA instead of defining MCA
1	Increase applicability of proposed requirements to all pipe outside of HCAs
1	Shorter compliance deadline (10 years) and shorter reassessment interval (15 years) for MCA assessments
1	Require pressure testing to verify MAOP for HCAs and Class 3 and 4 locations
1	No action[1]
3	Extend compliance deadlines
4	Checking under pipe supports; premium quality backfill; additional corrosion protection coating; additional gas stream processing/cleaning
5	Extend compliance deadlines
7	No action
7	Extend compliance deadlines

Table ES-11. Summary of Alternatives Analysis

Topic Area	Alternative
HCA = high consequence area MCA = moderate consequence area MAOP = maximum allowable operating pressure PIR = potential impact radius	

The alternatives analysis is subject to the same limitations and uncertainties associated with the analysis of the proposed rule.

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1. INTRODUCTION

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is proposing changes to the Federal pipeline safety regulations in 49 CFR Parts 191 and 192, which cover the transportation of gas by transmission and gathering pipelines. Specifically, PHMSA is proposing to issue new regulations or revise existing regulations in the following topic areas:

1. Integrity Assessment and Remediation for Segments Outside High Consequence Areas (HCAs) and to re-establish Maximum Allowable Operating Pressure (MAOP)
2. Integrity Management Program Process Clarifications
3. Management of Change
4. Corrosion Control
5. Inspection of Pipelines Following Extreme Events
6. MAOP Exceedance Reports and Records Verification
7. Launcher/Receiver Pressure Relief
8. Gas Gathering Pipeline Safety

This report provides analysis of the benefits and costs of the proposed regulatory changes by topic area.

1.1 BACKGROUND

This section provides background on the regulated industry.

<u>Overview of Gas Transportation Pipeline Systems</u>

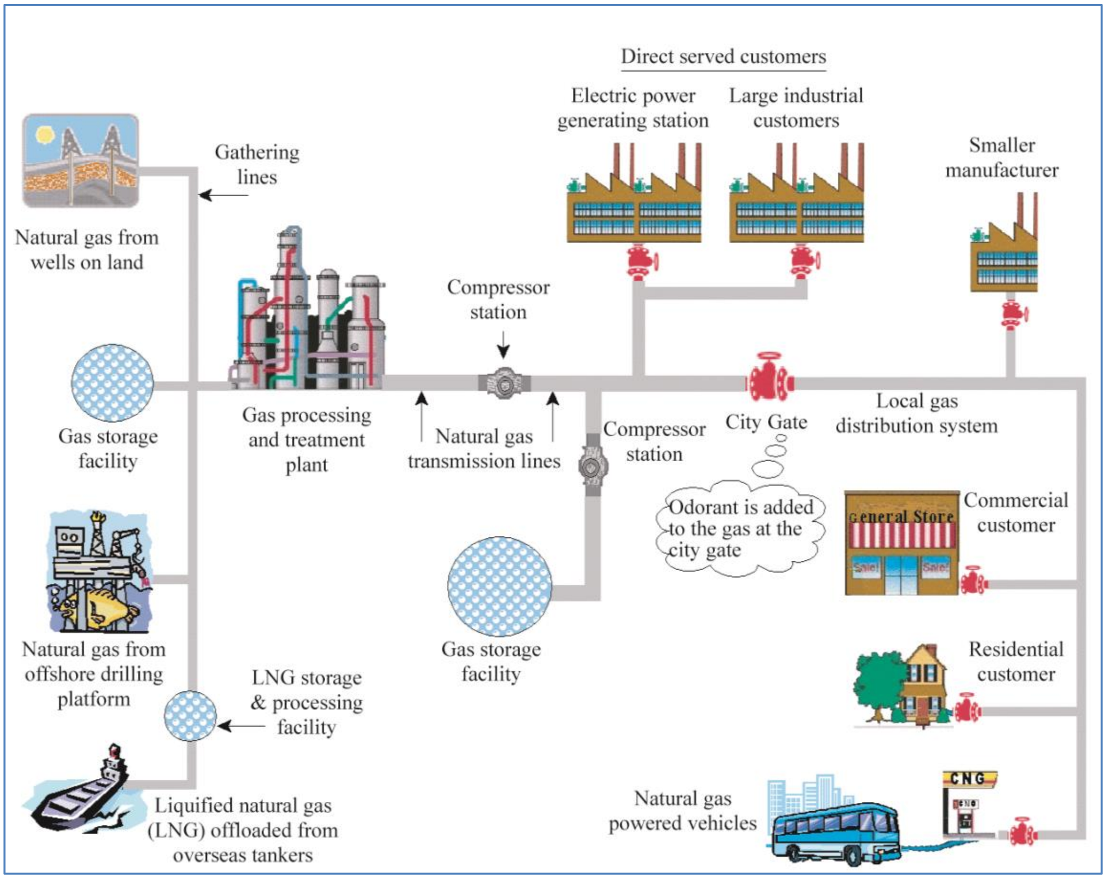
In accordance with 49 CFR §192.3, "transportation of gas"[2] means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce." This definition applies to the transportation of flammable, toxic, or corrosive gases, including gases other than natural gas,[3] such as propane, hydrogen, and synthetic gas when transported via pipeline in gaseous phase. However, for simplicity, only natural gas is referred to in the following discussion, since natural gas is by far the predominant commodity shipped by pipeline in the gaseous phase, representing 95% of the onshore mileage regulated by PHMSA.

<u>Natural Gas Pipeline Systems</u>

The natural gas infrastructure is composed of thousands of miles of pipelines, as well as processing facilities, and related components such as valves, controllers, and other such appurtenances. However, to envision the general overall pipeline infrastructure it is best to consider it in three different parts connected together to transport natural gas from the production field, where gas is extracted from underground, to the end user, where the gas is used as an energy fuel or as a raw material for production. These three parts are known as

[2] *Gas* means natural gas, flammable gas, or gas which is toxic or corrosive. 49 CFR §192.3
[3] Natural gas is a naturally occurring hydrocarbon gas mixture consisting primarily of methane.

gathering systems, transmission systems, and distribution systems. Each type of gas pipeline system can be seen to serve a particular purpose. The graphic below illustrates the overall pipeline infrastructure.



Gathering Pipeline Systems

As currently defined by Federal pipeline safety regulations (49 CFR 192.3), a gathering pipeline system "transports gas from a production facility to a transmission line or main." Before 2006, onshore gas gathering lines were exempt from regulation if they were outside the limits of any incorporated or unincorporated city, town, or village or outside any designated residential or commercial area such as a subdivision, business or shopping center, or community development. As a result, some gas gathering lines that pass close to areas where people work or live were not being regulated, simply because they were in "rural" areas; whereas, some portions where an incident would likely not affect people were regulated only because they were located in the city limits. To address these issues, and in response to a Congressional mandate, PHMSA revised its regulations in 2006 to more clearly define which portions of the natural gas pipeline network are "gathering" pipelines and which portions are regulated.

To determine if a gathering pipeline is a regulated line, an operator must use criteria in API RP 80,[4] subject to limitations listed in 49 CFR 192.8, to determine if a pipeline incident

[4] American Petroleum Institute (API) Recommended Practice (RP) 80, which is incorporated by reference into the Federal pipeline safety regulations (49 CFR 192.7).

could impact people by being close enough to a number of homes or to areas/buildings where people congregate.[5] Offshore gas gathering pipelines and high-pressure onshore lines meeting the criteria must meet requirements of 49 CFR Part 192 applicable to gas transmission pipelines. Onshore gas gathering pipelines that operate at lower pressures must comply with a subset of these requirements specified in §192.9.

Historically, gathering lines typically operated at relatively low pressures and flow rates, and had smaller diameters than transmission lines. However, with the recent significant expansion of high volume, high pressure natural gas production from unconventional geological formations, more gathering pipeline systems are being constructed and operated using parameters similar to transmission pipelines.

Transmission Pipeline Systems

Transmission pipelines are used to transport natural gas from gathering systems to processing and storage facilities. Along the way, gas may be extracted from the transmission pipelines into gas distribution systems or to directly serve industrial and agricultural customers. As defined in 49 CFR §192.3, "transmission line" means a pipeline, other than a gathering line, that: (1) transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress[6] of 20% or more of SMYS;[7] or (3) transports gas within a storage field.

Transmission pipeline systems include all of the equipment and facilities necessary to transport natural gas. This includes the pipe, valves, compressors, processing and storage facilities, and other equipment and facilities. Transmission pipelines are constructed from steel pipe and can range in size from several inches to several feet in diameter. They can be designed to operate from relatively low pressures to over 1000 pounds per square inch (psi) and can range in length from hundreds of feet to hundreds of miles. They can be intrastate, operating within the geographical boundaries of a single State, or interstate, operating across one or more State lines.

Most transmission pipelines are operated remotely from centrally-located control centers. These control centers allow for the efficient operation of either a single pipeline, or a number of different pipeline systems from a single location. From a single pipeline control center operators can start and stop compressors, open and close valves, monitor product movement, monitor leak detection systems, conduct training operations, and perform other system management tasks. Actions can be taken in response to field data transmitted from remote locations. Often, data observed at a central control center is confirmed by field personnel at affected locations before actions are taken.

Natural Gas Distribution Pipeline Systems

Most natural gas distribution systems are high-pressure distribution systems in that the gas

[5] The criteria for regulating gathering lines are described in more detail on Table 3.8-1, p. 108.
[6] *Hoop stress* is stress (force) exerted in a circumferential direction (perpendicular both to the axis and to the radius of the pipe) at a point in the pipe wall as a result of the pressure of the gas being transported.
[7] *SMYS* is the specified minimum yield strength for steel pipe manufactured in accordance with a listed specification. A common term used for steel pipe under PHMSA jurisdiction, SMYS provides an indication of the minimum stress the pipe may experience that will cause plastic (permanent) deformation of the pipe. SMYS is used to establish the MAOP of the pipe.

pressure in the "main" is higher than the pressure provided to the customer. A main in a distribution system serves as a common source of supply for multiple "service lines." A service line is a distribution system line that transports the gas from a common source of supply (i.e., a main) to one or more individual residential or small commercial customers, through a meter header or manifold. A customer meter is used to measure the volume of gas transferred from an operator to a consumer. A service line (and PHMSA jurisdiction) ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

Distribution system pipelines are generally smaller in diameter than gas transmission pipelines and operate at reduced pressures. Typically, gas is delivered to residential customers at pressures lower than the operating pressure of the mains, so a service regulator is used to limit the pressure of gas delivered to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.

Many gas distribution pipelines are made of plastic pipe rather than steel. Some antiquated systems still in operation are made from cast iron or ductile iron; however, these pipes are prone to corrosion and are being replaced. Distribution system mains are normally installed underground, along or under streets and roadways. Service lines connected to mains are also installed underground but their routing is less uniform.

Local distribution companies (LDCs) own and operate natural gas distribution pipelines. In some cases a municipal government may act as the LDC to operate the gas distribution system. LDCs receive natural gas from transmission pipelines and distribute it to commercial and residential end-users. The point at which the local distribution system connects to the natural gas transmission pipeline is known as the city gate. At the city gate the gas pressure is lowered and a sour-smelling odorant is added to the gas to help users detect even small quantities of leaking gas.

Pipeline Regulation

The Federal Energy Regulatory Commission (FERC)[8] is responsible for economic regulation of the transmission and sale of natural gas for resale in interstate commerce. The main objectives of economic regulation to ensure open access, non-discriminatory pricing, and protect shippers from the exercise of market power. FERC also approves the siting and abandonment of interstate natural gas facilities, including pipelines, storage facilities, and liquefied natural gas (LNG) facilities. FERC also ensures the safe operation and reliability of proposed and operating LNG terminals. However, FERC does not regulate or provide oversight for gas pipeline safety, nor does it regulate pipeline transportation on or across the Outer Continental Shelf. FERC does not regulate intrastate gas transmission, gathering lines, or local distribution systems; economic regulation of such systems is typically the responsibility of state regulatory commissions.

Pipeline operators are also regulated by EPA for air and water emissions under the Clean Air and Clean Water Acts, and for employee safety by the Occupational Safety and Health Administration.

PHMSA and its state partners regulate pipeline safety for jurisdictional gas gathering, transmission, and gas distribution systems, under minimum Federal safety standards

[8] See more information on FERC regulatory responsibilities for gas pipelines and facilities at www.ferc.gov.

authorized by statute[9] and codified by regulations in 49 CFR Part 192.[10] Generally, PHMSA regulates interstate pipelines directly, and delegates regulation of intrastate pipeline systems, including gathering lines and local distribution systems, to state agencies.

Federal regulation of gas pipeline safety began in 1968 with the issuance of interim minimum Federal safety standards for gas pipeline facilities and the transportation of natural and other gas, in accordance with the Natural Gas Pipeline Safety Act of 1968 (Public Law 90-481). The Interim Minimum Federal Standards basically adopted by reference existing state and industry standards and acknowledged that establishing an entirely new set of safety standards as required in the 1968 Act would take at least two years. The 1968 Act also provided that "Such standards may apply to the design, installation, inspection, testing, construction, extension, operations, replacement, and maintenance of pipeline facilities."

In 1970, DOT issued minimum safety standards to address multiple, various, and specific aspects of gas pipeline transportation. These included definitions and minimum requirements related to: gas pipeline construction; customer meters, service regulators and service lines; class locations; testing and uprating; and, pipeline materials, system components and facilities design.

In 1971, DOT began issuing minimum safety standards to address specific aspects of gas pipeline design, installation, inspection, testing, construction, operations, replacement, and maintenance. These standards began addressing aspects such as: corrosion control; confirmation of MAOP; repair sleeves; modification of pressure relief devices; qualification of pipe; gas odorization; welding; use of plastic pipe, caulked bell and spigot joints; and line markers. Experienced-based regulations continue to be issued today, and are often based upon issues, lessons learned, or needs identified through the investigation of individual gas pipeline incidents, and, in more recent years, knowledge gained through aggregate experience and data trends.

In some cases, although new safety standards have been established through regulations, related pipeline conditions may be exempted. For example, 49 CFR 192.619 establishes restrictions on operating a pipe segment in excess of the MAOP determined in accordance with that section. However, as noted in § 192.619(c), the requirements on pressure restrictions do not always apply: an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding dates specified in the regulation for the type of pipeline being considered. Those specified dates are usually prior to 1970, when relevant regulations were first written. In those cases, the operator is not currently required to pressure test the pipeline or otherwise verify the integrity of the pipeline to operate at pressure up to the MAOP.

Similarly, buried or submerged pipe installed after July 31, 1971 must be protected against external corrosion through the use of external protective coating and, with noted exceptions, a cathodic protection system.[11] Pipe installed before then is not required to have protective

[9] Title 49, United States Code, Subtitle VIII, Pipelines, Sections 60101, *et. seq.*
[10] Information is available on pipeline regulatory authorities at http://primis.phmsa.dot.gov/comm/Partnership.htm.
[11] A buried pipeline can act as an anode on a natural battery, leading to a flow of iron ions away from the pipeline and into the ground. Over time, this flow manifests itself as metal loss/corrosion of the pipeline. A cathodic protection system typically uses an electricity source to generate a counter flow current to an external anode, causing

coating and must have cathodic protection only in areas where active corrosion is found.

One specific issue with pipe manufactured before the 1970's is that some manufacturing techniques are prone to contain latent defects as a result of the manufacturing process. Line pipe manufactured using low frequency electric resistance welding (LF-ERW), lap welded pipe, or pipe with seam factor less than 1.0, is susceptible to failure of the longitudinal seam. These manufacturing techniques were widely used before regulations were promulgated in 1970, and many of those pipes are exempt from certain regulations, notably the requirement to pressure test the pipeline to establish MAOP. A substantial amount of LF-ERW pipeline is still in service.

"Pipeline integrity" means that the pipeline is of sound and unimpaired condition and can safely carry out its function under the conditions and parameters in which it operates. "Integrity management" encompasses the many activities pipeline operators must undertake to ensure the integrity of their pipelines. Integrity management regulations were promulgated in 2004 for gas transmission pipelines.

The institution of regulatory requirements for integrity management followed the gas transmission pipeline incident that killed 12 people near Carlsbad, New Mexico, on August 19, 2000. The pipeline was owned and operated by El Paso Natural Gas. Investigation into the failed pipe determined that the cause was severe internal corrosion resulting in a reduction in pipe wall thickness of over 70%. The integrity management process requires that operators perform a risk analysis, identify threats, periodically conduct integrity assessments, repair defects found, and implement additional preventive and mitigation measures to assure pipeline integrity for selected pipe segments located in defined High Consequence Areas. The process is intended to assure that case-specific threats and integrity issues, such as described above, are managed to prevent failures and assure pipeline integrity. Integrity management requirements for gas distribution pipeline systems were promulgated in 2009. PHMSA and State inspectors review operators' written IM programs and associated records to verify that the operators have used all available information about their pipelines to assess risks and take appropriate actions to mitigate those risks.

However, infrequent severe incidents indicate that some pipelines continue to be vulnerable to legacy issues, such as LF-ERW pipe. Also, some severe pipeline incidents have occurred in areas outside HCAs where the application of integrity management principles is not required. Data shows that gas pipelines continue to experience significant incidents and that some historical failure causes (such as corrosion) have still not been effectively addressed, and mitigative measures (such as rupture detection and response) have not been entirely effective in preventing or mitigating the impacts of gas pipeline incidents. Organizations such as the General Accounting Office (GAO) and the National Transportation Safety Board (NTSB) have made numerous recommendations for improving gas safety regulations. Congress has mandated that PHMSA address certain issues through specific legislation. The proposed rule is intended to address some of those recommendations and legislative requirements.

On August 25, 2011, PHMSA published an Advance Notice of Proposed Rulemaking

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the pipeline to become a cathode, and hence to cease losing iron ions.

(ANPRM) seeking public comment on the following topics[12]:

A. Modifying the definition of HCAs
B. Strengthening requirements to implement preventive and mitigative (P&M) measures for pipeline segments in HCAs
C. Modifying repair criteria
D. Improving requirements for collecting, validating, and integrating pipeline data
E. Making requirements related to the nature and application of risk models more prescriptive
F. Strengthening requirements for applying knowledge gained through the Integrity Management Program (IMP)
G. Strengthening requirements on the selection and use of assessment methods
H. Valve spacing and the need for remotely or automatically controlled valves
I. Corrosion control
J. Pipe manufactured using longitudinal weld seams
K. Establishing requirements applicable to underground gas storage
L. Management of change
M. Quality management systems (QMS)
N. Exempting facilities installed prior to the regulations
O. Modifying the regulation of gas gathering lines

PHMSA received 103 comment letters in response to the ANPRM. Comments submitted to the docket were received from the pipeline industry, government agencies, pipeline trade associations, citizen groups, private citizens, consultants, municipalities, and trade unions. PHMSA's responses to these comments are included in the accompanying NPRM.

On August 30, 2011, after the ANPRM was issued, the NTSB adopted (as final) its report on the San Bruno, California gas transmission pipeline incident that occurred on September 9, 2010. In its report, the NTSB issued safety recommendations P-11-1 and P-11-2 and P-11-8 through -20 to PHMSA, P-10-2 through -4 and P-11-24 through -31 to the pipeline operator, Pacific Gas & Electric (PG&E), and P-10-4 through -6 and P-11-22 and -23 to the California Public Utilities Commission (CPUC), among others. PHMSA considered several of these NTSB recommendations directly related to the topics addressed in the ANPRM and in developing this proposed rule.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act) was signed into law on January 3, 2012, also after the ANPRM was issued. Several of the Act's statutory requirements address the topics considered in the ANPRM and have had a

[12] 76 FR 53086 Pipeline and Hazardous Materials Safety Administration, Pipeline Safety, 49 CFR Part 192, [Docket No. PHMSA–2011–0023] ANPRM. The ANPRM may be viewed at http://www.regulations.gov.

substantial impact on PHMSA's approach to this proposed rulemaking.

The Notice of Proposed Rulemaking (NPRM) addresses additional topics that have arisen since issuance of the ANPRM, including NTSB Recommendation P-14-1, issued in response to a gas transmission pipeline incident on December 11, 2012 in Sissonville, West Virginia, and the August 2014 Government Accountability Office Report GAO-14-667.[13] GAO reviewed oil and gas transportation infrastructure issues and recommended that DOT move forward with proposed rulemaking to address safety risks, including emergency response planning from newer gathering pipelines.

1.2 PROPOSED RULE

Based on the ANPRM, comments received, and the subsequent activities as described above, PHMSA is proposing to make the following changes to the Federal pipeline safety regulations set forth in 49 CFR Parts 191 and 192.

1. Re-establish MAOP, Verification of Material Properties, and Integrity Assessment and Remediation for Segments Outside HCAs
    a. In accordance with the Congressional Mandate, require that pipeline operators conduct special integrity assessments, such as pressure tests or inline inspections (ILI) in conjunction with engineering critical assessments, to re-establish MAOP for selected pipeline segments that were previously exempted from testing under a grandfather clause, if they operate at pressures that exceed 30% of SMYS and are located in a HCA.
    b. In accordance with the Congressional Mandate, require that pipeline operators re-verify material properties and conduct special integrity assessments, such as pressure tests or ILI in conjunction with engineering critical assessments, to re-establish MAOP for selected pipeline segments that that do not have adequate records to establish MAOP if they are located in a HCA or a Class 3 or 4 location.
    c. Require initial and periodic integrity assessments and remediation for non-HCA pipelines in newly-defined moderate consequence areas (MCAs). Data analysis requirements, assessment methods, and repair criteria for immediate conditions would be the same as for HCAs. Repair criteria for two-year conditions in MCAs would be the same as the current one-year conditions for HCAs. Assessments conducted to re-establish MAOP would count as an initial assessment or re-assessment, as applicable, under the proposed non-HCA assessment rule or 49 CFR Part 192, Subpart O (HCAs).
    d. To address NTSB Recommendation P-11-14, require that pipeline operators conduct special integrity assessments, such as pressure tests or ILI in conjunction with engineering critical assessments, to re-establish MAOP for selected pipeline segments that were previously exempted from testing under a grandfather clause, (i) if they operate at pressures less than or equal to 30% of SMYS and are located in a HCA, or (ii) if the pipeline segment operates at

[13] Government Accountability Office (GAO) Report to Congressional Requestors, *Department of Transportation Is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to Improve Pipeline Safety*, Report No. GAO-14-667, August 2014. http://www.gao.gov/products/GAO-14-667

pressures greater than or equal to 20% of SMYS that is located in a Class 3 or 4 location, or in a piggable pipeline located in a newly defined MCA in a Class 1 or 2 location.

2. IMP Process Clarifications

   a. Clarify IMP process requirements in the following areas: management of change; threat identification; risk assessments; baseline assessment methods; preventive and mitigative measures; periodic evaluations and assessments; and, notifications for reassessment interval extensions.

   b. Clarify (and, in limited cases, revise) repair criteria for remediating defects discovered in HCA segments.

   c. Require notification to PHMSA if the operator cannot obtain sufficient information to determine if a condition presents a potential threat to the integrity of the pipeline within 180 days of completing an assessment.

3. Management of Change – Require gas transmission pipeline operators to evaluate and mitigate risks as necessary, during all phases of the useful life of a pipeline, including management of change. Each operator would have to develop and follow a management of change process that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary.

4. Corrosion Control – Expand corrosion control requirements in the following areas: pipe coating assessments; remedial actions for external corrosion mitigation deficiencies; close interval surveys; interference current remedial actions; gas stream monitoring program; and preventive and mitigative measures for internal and external corrosion control.

5. Inspection of Pipelines Following Extreme Events – Require inspections of pipelines in areas affected by extreme weather, man-made and natural disasters, and other similar events. Such inspections would ensure that pipelines are still capable of being safely operated after these events and would identify the mitigative and corrective actions that might be required to ensure safe operation.

6. MAOP Exceedance Reports and Records Verification – Require reporting of MAOP exceedances, development of operation and maintenance procedures to assure MAOP is not exceeded by the amount needed for overpressure protection, and verification of MAOP-related records. Also, clarify records preparation and retention requirements.

7. Launcher/Receiver Pressure Relief – Require any launcher or receiver for inline tools be equipped with a device capable of safely relieving pressure in the barrel before opening of the launcher or receiver barrel closure or flange and insertion or removal of inline inspection tools, scrapers, or spheres. Require the use of a suitable device to indicate that pressure has been relieved in the barrel, or provide a means to prevent opening of the barrel closure or flange, or prevent insertion or removal of inline inspection tools, scrapers, or spheres, if pressure has not been relieved. These requirements would enhance safety when performing maintenance and inspection activities that utilize launchers and receivers to insert and remove maintenance tools

and devices.

8. Expansion of Regulated Gas Gathering Pipelines
    a. Revise the current definition of a "gas gathering line," including repealing the use of API RP 80 as the regulatory basis for identifying regulated onshore gas gathering lines.
    b. Create a new category of "Type A"[14] regulated onshore gas gathering lines made up of the relatively higher risk lines that are not currently regulated.
    c. Repeal the current exemption for certain gas gathering lines for the immediate notice and reporting of incidents, the reporting of safety-related conditions (SRC) and annual pipeline summary data, and reporting into PHMSA's national registry of pipeline operators.

These changes would improve the safety and protection of pipeline workers, the public, property, and the environment by improving the detection and remediation of unsafe conditions, mitigating the adverse effects of pipeline failures, and ensuring that certain currently unregulated pipelines are subject to appropriate regulatory oversight. In addition to safety benefits, the rule will improve and extend the economic life of critical pipeline infrastructure that transports domestically produced natural gas energy, thus supporting national energy economic and security objectives.

1.3 ORGANIZATION OF REPORT

The remainder of the body of this report is organized as follows:

- Section 2, Regulatory Analysis, describes the purpose of the analysis, baseline, study period, and alternatives.
- Section 3, Analysis of Costs, discusses the need for the regulation, the impact of the regulation, assumptions underlying the cost analysis, and detailed estimates of costs for Topic Areas 1 through 7 (gas transmission provisions).
- Section 4, Analysis of Benefits, provides analysis of safety and environmental [avoided greenhouse gas (GHG) emissions] benefits from Topic Areas 1 through 7 (gas transmission provisions).
- Section 5, Comparison of Benefits and Costs for Topic Areas 1 through 7, provides a comparison of the estimated benefits and costs for the gas transmission provisions.
- Section 6, Benefit Pertaining to Topic Area 8, provides analysis of safety and environmental (avoided GHG emission) benefits from the gas gathering provisions.
- Section 7, Benefit-Costs Analysis Pertaining to Topic Area 8, provides a comparison of benefits and costs for the gas gathering provisions.
- Section 8, Evaluation of Unfunded Mandate Act Considerations, provides analysis of potential state costs.

Several appendices provide supplemental information:

[14] Type A and Type B onshore gathering lines are defined in 49 CFR 192.8.

- Appendix A, Supplemental Calculations for Estimation of Topic Area 1 Costs
- Appendix B, Social Costs of Greenhouse Gas Emissions
- Appendix C, Rate of Incident Prevention as a Function of Assessment Mileage
- Appendix D, Consequences of San Bruno Incident
- Appendix E, Consequences of Historical Incidents.

2. REGULATORY ANALYSIS

This section describes the purpose of the analysis, the baseline for measuring the incremental impact of the proposed rule, the timeframe and structure of the analysis, including alternatives.

All data, unless otherwise stated, is obtained from annual reports, incident reports, or IMP performance metrics submitted to PHMSA by pipeline operators as required by 49 CFR Parts 191, 192, and 195.

2.1 PURPOSE OF THE ANALYSIS

U.S. Code, Title 49, Chapter 601, Section 60102 specifies that the Department of Transportation (DOT), when prescribing any pipeline safety standard shall consider relevant available gas and hazardous liquid pipeline safety information, environmental information, the appropriateness of the standard, and the reasonableness of the standard. In addition, DOT must, based on a risk assessment, evaluate the reasonably identifiable or estimated benefits and costs expected to result from implementation or compliance with the standard. This preliminary Regulatory Impact Analysis fulfils this statutory requirement.

Executive Order 12866 of September 30, 1993, Regulatory Planning and Review, directs all Federal agencies to assess the benefits and costs of "significant regulatory actions," and assess the benefits and costs of alternatives for rules expected to have an annual impact on the economy of $100 million or more. The Executive Order also requires a determination as to whether a proposed rule could adversely affect the economy or a section of the economy in terms of productivity and employment, the environment, public health, safety, or State, local, or tribal governments. Furthermore, the Regulatory Flexibility Act of 1980, as amended, requires Federal agencies assess the economic impact of proposed rules on small entities. The UMRA also requires an impact analysis for rules that that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $153 million or more ($100 million in 1995 dollars, adjusted for inflation for 2013) in any one year.

In accordance with the above directives, this analysis examines the potential compliance costs and benefits of the proposed rule and other feasible regulatory alternatives.

2.2 BASELINE FOR THE ANALYSIS

The proposed rule would apply to gas transmission and gathering pipelines. The current infrastructure in the United States for regulated gas transmission and gathering pipelines is characterized in the tables below.

Table 2-1 Pipeline Infrastructure - Gas Transmission (2015)

System Type	Onshore Miles	Total Miles	Number of Operators
Interstate	192,217	196,033	156
Intrastate	105,668	105,757	891
Total	297,885	301,790	See note 1

Source: PHMSA Pipeline Data Mart
1. Entities may operate both inter- and intrastate pipelines. There are 1,017 total operators.

Table 2-2 Pipeline Infrastructure - Regulated Onshore Gas Gathering (2015)

Type A Miles[1]	Type B Miles[2]	Total Miles	Number of Operators
7,844	3,580	11,424	367

Source: PHMSA Pipeline Data Mart
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations

The IMP rule, "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas,"[15] is the previous significant gas transmission pipeline rulemaking related to most of the requirements in the proposed rule. The Integrity Management (IM) requirements in 49 CFR Part 192, Subpart O specify how pipeline operators must identify, prioritize, assess, evaluate, repair and validate, through comprehensive analyses, the integrity of gas transmission pipelines in HCAs. Although operators may voluntarily apply IM practices to pipeline segments that are not in HCAs, the regulations do not require operators to do so.

Currently, approximately 7% of onshore gas transmission pipelines are located in HCAs. However, coincident with integrity assessments of HCA segments, pipeline operators have assessed substantial amounts of pipeline in non-HCA segments. The Interstate Natural Gas Association of America (INGAA), a trade group representing approximately 200,000 miles of interstate natural gas pipelines, noted in its ANPRM comments that approximately 90% of members' Class 3 and 4 pipeline mileage not in HCAs are presently assessed through testing during IM assessments.[16] This is because ILI and pressure testing cover large continuous pipeline segments which may contain both HCA mileage and non-HCA mileage. Operators may also have assessed non-HCA mileage for various other reasons.

Separately, based on the IM principle of continuous improvement, INGAA members committed to extend by 2012 some level of IM to pipeline segments where approximately 90% of people who live, work or otherwise congregate within the potential impact radius (PIR) of a given pipeline. INGAA members have committed to apply full IM programs to those segments by 2020. Assessment and repair reporting in operators' annual report submissions suggest that operators are assessing a significant amount of miles outside of HCAs. [17]

With respect to gas gathering pipelines, the current baseline is PHMSA's "Gas Gathering Line Definition; Alternative Definition for Onshore Lines and new Safety Standards," (Final Rule effective April 14, 2006).[18] In that rule PHMSA distinguished regulated onshore

[15] [68 FR 69778] 49 CFR Part 192 [Docket No. RSPA–00–7666; Amendment 192–95] Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)
[16] See http://www.ingaa.org/about.aspx. Refers to assessing non-HCA segments in conjunction with integrity assessments of HCA segments, by virtue of the proximity and continuity of the segments.
[17] For example, 2014 reports show that operators assessed approximately 26,000 miles using metal loss ILI tools, ECDA, pressure tests, and other methods.
[18] [71 FR 13289] 49 CFR Part 192 [Docket No. PHMSA–1998–4868; Amendment 192–102] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards

gathering lines from other gas pipelines and production operations. PHMSA also established safety rules for certain onshore gathering lines in rural areas and revised current rules for certain onshore gathering lines in non-rural areas.

2.3 TIME PERIOD OF THE ANALYSIS

The proposed rule would require that gas transmission pipeline operators conduct additional integrity assessments of an estimated 16,600 miles of gas transmission pipeline. The proposed rule would also establish a deadline for completing the initial assessments within 15 years of the effective date of the rule, and require operators to reassess pipelines in newly defined "moderate consequence areas" more than 20 years after the previous assessment. Therefore, this analysis evaluates the costs and benefits for the 15-year initial compliance period and used the same time frame for all topic areas for both gas transmission and gas gathering pipelines.

2.4 ALTERNATIVES

In general, PHMSA considered relaxed compliance deadlines and/or 'no action' alternatives for each topic area.

For Topic Area 1, PHMSA considered a broader scope intended to address more pipe segments to which NTSB Recommendations P-11-14 and P-11-15 would apply. Several other alternatives underwent a screening evaluation.

For Topic Area 8 (expansion of regulated gas gathering lines), PHMSA also considered applying some safety regulations to all currently unregulated gas gathering lines (instead of restricting the new regulations to a subset of lines).

The alternatives considered by PHMSA, and the rationale for not selecting those alternatives, are discussed in more detail for each topic area in Sections 5.6 (gas transmission) and 7.6 (gas gathering).

3. ANALYSIS OF COSTS

This section provides detailed analysis for each topic area and includes a summary of the proposed regulatory changes, the need for the regulations (problem statement), assessment of the incremental impact, assumptions underlying the analysis, and the data, method, and resulting estimates of incremental cost.

3.1 RE-ESTABLISH MAOP, VERIFY MATERIAL PROPERTIES, AND INTEGRITY ASSESSMENT OUTSIDE HCAS

Topic Area 1 includes the following proposed changes to the current regulations:

1. Addition of "moderate consequence area" (MCA) and "occupied site" definitions to be used to determine the scope of pipelines subject to the assessment requirements in 49 CFR § 192.710, the MAOP verification requirements in 192.624, and the material documentation requirements in 192.607. [§ 192.3]
2. Material documentation requirements for segments that lack adequate documentation. [§ 192.607]
3. Re-verification of MAOP, which in most cases would require an integrity assessment that meets specific requirements, or equivalent. [§§ 192.619(e) and 192.624]
4. Non-HCA assessments. [§ 192.710]
    a. Data analysis requirements for assessments conducted (same as HCA)
    b. Assessment methods (same as HCA)
5. Repair requirements and schedules for non-HCA anomalies and conditions discovered as a result of the assessments required by 49 CFR § 192.710 or 192.624. [§ 192.711, § 192.713]
    a. Immediate conditions (same as HCA)
    b. Two year conditions (same as one year conditions in HCA)

3.1.1 PROBLEM STATEMENT

PHMSA developed the proposed regulations in Topic Area 1 to address a number of statutory provisions and NTSB recommendations:

- The Act §23(d) (Issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30% of SMYS.)
- The Act §23(c) (Require the operator to reconfirm MAOP as expeditiously as economically feasible; and determine what actions are appropriate for the pipeline owner or operator to take to maintain safety until a maximum allowable operating pressure is confirmed.)
- The Act §5(a) and §5(f) (Evaluate whether integrity management system requirements, or elements thereof, should be expanded beyond HCAs, and issue final regulations if the Secretary finds that integrity management system requirements, or elements thereof, should be expanded beyond HCAs.)
- NTSB Recommendation P-11-14 (Amend 49 CFR § 192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.)

- NTSB Recommendation P-14-1 (Add principal arterial roadways including interstates, other freeways and expressways, and other principal arterial roadways as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures to the list of "identified sites" that establish a HCA.)

These mandates and recommendations are related: all address pipeline integrity under operating conditions. 49 CFR Part 192, Subpart O requires periodic integrity assessments for pipe segments located in HCAs (approximately 20,000 of 300,000 miles, or seven percent, of onshore gas transmission pipelines). Part 192 does not require integrity assessments of pipeline segments that are not in HCAs. The proposed rule would require operators to conduct integrity assessments for onshore non-HCA segments within 15 years of the effective date of the rule, and every 20 years thereafter.

The proposed rule would establish a newly-defined MCA to identify additional non-HCA pipeline segments that would require integrity assessments. MCA means an onshore area that is within a potential impact circle, as defined in § 192.903, containing five or more buildings intended for human occupancy, an occupied site, or a right-of-way for a designated interstate, freeway, expressway, and other principal four-lane arterial roadway as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures, and does not meet the definition of HCA. Requirements for data analysis, assessment methods, and immediate repair conditions would be similar to requirements for HCA segments. Two-year repair conditions for MCA segments would be the same as one-year repair conditions for HCA segments. These changes would ensure the prompt remediation of anomalous conditions that could potentially impact people, property, or the environment, commensurate with the severity of the defects, while allowing operators to allocate their resources to HCAs on a higher-priority basis.

The proposed rule would require operators to verify or establish material properties for pipelines in HCAs and Class 3 and Class 4 locations for which adequate documentation is missing or unavailable. Operators can take advantage of opportunities where pipe segments are exposed for maintenance or repair (e.g., to repair defects identified during an integrity assessment), to conduct tests and examinations to confirm and document key properties and attributes of the pipeline.

Operators of segments in HCAs or MCAs for which MAOP was established in accordance with § 192.619(c) or otherwise do not have an adequate basis for the existing MAOP would be required to re-establish or re-validate MAOP through pressure testing or other means as defined in the proposed rule. In almost every case, this would require integrity assessment and repair of discovered defects. Assessments conducted for these purposes could be credited toward meeting other integrity assessment requirements found in 49 CFR Part 192, Subpart O, or the proposed § 192.710.

3.1.2 ASSESSMENT OF REGULATORY IMPACT

The largest impact of Topic Area 1 is the integrity assessment of pipe for which MAOP must be re-established, and for segments located in newly defined MCAs for which MAOP does not need to be confirmed. The proposed rule would include specific repair criteria for timely remediation of pipeline defects discovered through integrity assessments, and material documentation requirements.

Coincident with integrity assessments of HCA segments, pipeline operators have assessed substantial amounts of pipeline in non-HCA segments. The proposed rule would allow the use of those prior assessments for non-HCA segments in complying with the new requirements. PHMSA accounted for this circumstance in this analysis.

There is some overlap of the proposed requirements (i.e., integrity assessment activities serve to comply with multiple requirements) in this Topic Area. However, to help understand the relative scope of each requirement, PHMSA evaluated each separately:

- Section 3.1.4 addresses the Act §23(d)
- Section 3.1.5 addresses the Act §23(c)
- Section 3.1.6 addresses the Act §5(a) and §5(f)
- Section 3.1.7 addresses NTSB Recommendation P-11-14.

NTSB Recommendation P-14-1 is addressed via the MCA definition which informs and establishes the scope of pipeline segments to which the proposed requirements apply.

3.1.3 ANALYSIS ASSUMPTIONS

The sections below present analysis of the incremental cost of the proposed changes. To estimate costs, PHMSA assumed that certain characteristics of pipelines in HCAs apply to non-HCA pipe and combined this information with data collected on regulated pipelines from operator annual reports to approximate the scope and condition of the non-HCA lines to be assessed under the proposed rule. These assumptions were necessary because data for non-HCA segments is limited, and there is no data related to the population of pipelines that could meet the new definition for MCA.

Because operators must already repair pipeline defects that are injurious to the pipe, the specific repair criteria proposed by PHMSA do not represent new repair standards, but affect the timeliness of repairs. The cost of performing repairs of defects discovered as a result of the mandatory integrity assessments is therefore baseline operating and maintenance requirements. (Repair costs are also not included in baseline incident costs used to estimated benefits. See Appendix E for a fuller discussion.) The only cost to operators of implementing the repair timeliness criteria is the time cost of money for completing some repair more quickly than an operator might have done prior to this rulemaking. This cost is negligible compared to the cost of conducting assessments.

The analysis is based on the assumption that all defects discovered by the testing and assessment requirements would be either repaired or result in an incident. Performing repairs sooner than in the absence of the proposed rule, and thus averting incidents, is the basis for the estimated benefits. It is possible that such repairs could be required on pipelines that, absent the rule, operators would replace before discovering the defects. PHMSA invites comments on these issues and costs.

Because operators must have already performed analysis in order to have identified HCAs, or verify that they have no HCAs, PHMSA assumed that the cost of identifying MCAs is negligible compared to the cost of assessments and did not quantify the cost to identify MCAs.

3.1.4 ESTIMATION OF COMPLIANCE COSTS TO RE-ESTABLISH MAOP: PREVIOUSLY UNTESTED PIPE

Topic Area 1 addresses the statutory requirement in the Act §23(d), which requires that PHMSA issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30 percent of SMYS. In developing the regulations, PHMSA considered safety testing methodologies, including pressure testing and other alternative methods, including in-line inspections that are of equal or greater effectiveness. PHMSA would allow operators to select from several methods. The primary methods PHMSA expects operators to use would be ILI in conjunction with an engineering critical assessment (ECA) or pressure testing. Other options were provided in the rule (such as replacing the pipeline or derating the pipeline). However, these other options are extreme measures, and more costly; hence PHMSA expects operators to use ILI/ECA or pressure testing for virtually all segments to which these requirements would apply. The rule also would establish timeframes for the completion of such testing that take into account potential consequences to public safety and the environment and that minimize costs and service disruptions.

PHMSA used the following steps to estimate costs of assessments to re-establish MAOP:

1. Estimate the mileage of previously untested pipe segments.
2. Estimate the breakdown of assessment methods.
3. Estimate the unit costs of each assessment method.
4. Estimate total incremental compliance costs.

3.1.4.1 Estimation of Mileage of Previously Untested Pipe

Operators report the mileage of pipeline segments in HCAs that were not pressure tested to establish MAOP. To estimate the mileage subject to the requirement, PHMSA proportionally adjusted the mileage in each class location[19] by the proportion of pipe operated at an MAOP greater than 30% SMYS, also reported by operators (**Table 3-1**). **Table 3-2** shows the resulting estimate of applicable pipe.

Table 3-1. Onshore Gas Transmission Mileage by Percent SMYS

Location	Total	<20% SMYS	20-30% SMYS	>30% SMYS	Percent >30% SMYS
Interstate					
Class 1	160,381	6,750	7,975	145,656	91%
Class 2	17,811	1,460	1,433	14,918	84%
Class 3	13,925	1,302	1,305	11,319	81%
Class 4	29	4	9	16	55%
Total	192,146	9,516	10,722	171,908	89%
Intrastate					
Class 1	72,254	7,975	8,245	56,034	78%
Class 2	12,820	1,065	2,737	9,018	70%

[19] Class Locations are defined in 49 CFR §192.5 and are based primarily on housing density near the pipe segment. Class 1 has the lowest density while Class 4 locations are the densest. Suburban residential areas are typically Class 2 or Class 3 locations.

Table 3-1. Onshore Gas Transmission Mileage by Percent SMYS					
Location	**Total**	**<20% SMYS**	**20-30% SMYS**	**>30% SMYS**	**Percent >30% SMYS**
Class 3	19,726	2,241	5,610	11,876	60%
Class 4	880	23	427	430	49%
Total	105,680	11,303	17,019	77,358	73%
Source: 2014 PHMSA Gas Transmission Annual Report SMYS = specified minimum yield strength					

Table 3-2. Estimate of Previously Untested Onshore Gas Transmission Mileage in HCAs Operating at Greater than 30% SMYS			
Location	**Previously Untested HCA[1]**	**Percent >30% SMYS**	**HCA ≥ 30% SMYS[2]**
Interstate			
Class 1	62	91%	59
Class 2	23	84%	19
Class 3	439	81%	357
Class 4	0	55%	0
Total	524	89%	432
Intrastate			
Class 1	13	78%	10
Class 2	18	70%	13
Class 3	749	60%	451
Class 4	5	49%	3
Total	786	73%	476
HCA = High consequence area SMYS = specified minimum yield strength 1. Source: PHMSA 2014 Annual Report 2. See Appendix A.			

3.1.4.2 Estimation of Breakdown of Assessment Methods

The methods specified in the proposed rule (§ 192.624) include pressure testing to include a spike pressure test (§ 192.506) if the pipeline includes legacy pipe or is constructed using legacy construction techniques, or if there has been a reportable in-service incident (§ 191.3) since the most recent successful pressure test due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect. For modern pipe without the aforementioned risk factors, a pressure test in accordance with § 192.505 would be allowed. The proposed rule would also allow operators to re-establish MAOP by the use of an ILI program in conjunction with an ECA process (using technical criteria to establish a safety margin equivalent to a pressure test). Other methods to re-establish MAOP would also be allowed, including de-rating or replacing the pipe segment, or use of other technology that the operator demonstrates provides an equivalent or greater level of safety. However, PHMSA determined that the cost of pipe replacement or derating would be greater than the pressure test and ILI/ECA test methods (pipe replacement costs are presented in Table 3-63; derating would result in substantial revenue loss to operators.)

PHMSA estimated compliance costs assuming that operators would re-establish MAOP by

ILI/ECA for pipelines able to accommodate ILI tools, commonly referred to as "smart pigs" (i.e., they are "piggable"), upgrading to accommodate ILI tools, or a pressure test. Beginning in 2012, PHMSA required operators to report pipeline mileage that is piggable (**Table 3-3**). PHMSA used this data to estimate the mileage that would be assessed by ILI as-is. PHMSA assumed that operators would comply through use of ILI on segments that are piggable given the lower costs associated with ILI assessments.

Table 3-3: Percent of Miles Capable of Accepting an Inline Inspection Tool

Class Location	HCA	Non- HCA
Interstate		
Class 1	95%	71%
Class 2	94%	70%
Class 3	89%	60%
Class 4	94%	56%
Intrastate		
Class 1	68%	53%
Class 2	66%	40%
Class 3	55%	33%
Class 4	49%	62%
Source: PHMSA 2014 Gas Transmission Annual Report		

Beginning in 2010, PHMSA required operators to report the type of assessment method used to perform integrity assessments. The breakdown of mileage assessed by each assessment method for 2010-2014 is presented in **Table 3-4**. The relatively high percentage of intrastate pipeline assessed by pressure test and direct assessment in the 2010-2014 time period is attributed to the fact that a larger percentage of intrastate pipelines are unable to accommodate ILI tools (i.e., they are not "piggable").

Table 3-4. Miles of Onshore Gas Transmission Pipeline for which Integrity Assessment was Conducted (2010-2014)

Year	ILI	Pressure Test	Direct	Other	Total
Interstate					
2010	15,308	567	177	85	16,136
2011	17,366	829	157	29	18,380
2012	18,656	846	126	42	19,670
2013	15,687	739	106	144	16,675
2014	15,820	1,008	116	11	16,954
Total	82,837 (94%)	3,988 (5%)	681 (0%)	309 (0%)	87,816 (100%)
Intrastate					
2010	4,792	826	1,539	1,191	8,348
2011	3,920	858	1,842	1,046	7,666
2012	5,041	1,232	2,085	2,570	10,929
2013	5,663	763	1,894	782	9,100
2014	5,801	807	1,641	750	8,998

Table 3-4. Miles of Onshore Gas Transmission Pipeline for which Integrity Assessment was Conducted (2010-2014)

Year	ILI	Pressure Test	Direct	Other	Total
Total	25,218 (56%)	4,486 (10%)	9,000 (20%)	6,338 (14%)	45,042 (100%)

Source: PHMSA Gas Transmission Annual Reports: 2010-2014

For pipelines that are not piggable, PHMSA assumed that operators would either pressure test the segment or upgrade it to accommodate an ILI tool. PHMSA applied its experience with historical piggability and assessment methods to estimate the percent of miles which will be pressure tested and upgraded to ILI under the proposed rule (**Table 3-5**).

Table 3-5. Estimated Assessment Method for Previously Untested Pipe in High Consequence Areas (Percent of Mileage)

Location	ILI [1]	Pressure Test[2]	ILI Upgrade[2]
Interstate			
Class 1	95%	5%	0%
Class 2	94%	5%	1%
Class 3	89%	5%	6%
Class 4	94%	0%	6%
Intrastate			
Class 1	68%	10%	22%
Class 2	66%	20%	14%
Class 3	55%	20%	25%
Class 4	49%	21%	30%

1. Source: PHMSA 2014 Gas Transmission Annual Report
2. PHMSA best professional judgment based on historical piggability and assessment methods (Tables 3-3 and 3-4).

PHMSA assumed that operators would assess an equal percent of mileage in each year of the 15-year compliance period. Therefore the annual cost of any given component is the total cost divided by 15 years. This assumption may result in an overestimate of discounted costs and benefits as operators may elect to complete costlier or more complex assessments such as pressure tests and ILI upgrades later in the program period.

3.1.4.3 Estimation of Unit Costs of Assessment

This section describes the estimation of unit costs for assessment methods.

Upgrade to ILI

PHMSA developed unit costs to upgrade to accommodate ILI and run ILI tools based on best professional judgment (BPJ). PHMSA developed estimates of the overall average unit ILI upgrade components and costs by pipeline category. These estimates represent a national average cost for each category, and are comprehensive of all upgrade costs, including materials, labor, right of way agreements and permitting, and cleanup.[20]

[20] Based on design pressure of 800 pounds (no more than 1000 pounds) and fittings of ANSI 600.

Additionally, upgrading pipelines generally requires operators to empty the natural gas from the pipeline via a procedure called "blowdown" which entails releasing natural gas into the atmosphere. PHMSA calculated the amount of gas that would be released through this procedure per mile using **Equation 1**.

Equation 1: $\boldsymbol{Vb} = (\mathbf{28.798} * (\boldsymbol{Tb/Pb}) * (\boldsymbol{Pavg}/(\boldsymbol{Zavg} * \boldsymbol{Tavg})) * \boldsymbol{D^2})/\mathbf{1000}$

Where:

Vb = Volume of gas released per mile (thousand cubic feet; MCF)

Tb = Temperature at standard conditions (70 degrees F)

Pb = Pressure at standard conditions (14.7 pounds per square inch; PSI)

Pavg = Pressure at blowdown conditions (100 PSI for intrastate; 150 PSI for interstate)

Zavg = Compressibility factor at packed conditions (0.88)

Tavg = Temperature at packed conditions (70 degrees F)

D = inside diameter of pipeline in inches (29.25 for 30-inch pipes, 15.25 for 16-inch pipes, and 7.5 for 8-inch pipes)

To value the gas lost during upgrade and inspection-related blowdown, PHMSA used data on the volume and cost of gas released during intentional controlled blowdowns conducted as part of responding to or recovering from incidents, based on incident report data (Part A). Between 2010 and 2014, there were 294 incident reports that included intentional releases. PHMSA calculated the unit cost of natural gas for each case by dividing the cost of gas released intentionally[21] by the volume of gas released intentionally. The median natural gas price in these incidents was $4.21 per MCF. Note that this gas price may not be representative of the cost of gas released during planned controlled blowdowns for pipe upgrades, since operators may not be able to plan for incident-related blowdowns as cost-effectively as they would for planned pipeline upgrades. As such, this approach may result in an overestimate of blowdown costs associated with upgrades.

The gas lost during blowdown represents GHG emissions which have additional, external costs to society. PHMSA accounted for these additional social costs separately, and they are not reflected in the unit costs described in this section.

Table 3-6 shows the calculated unit costs (i.e., cost per mile) including both upgrade and blowdown costs for pipelines in Class 1 and Class 2 non-HCA locations. The estimates range from $14,700 to $78,700 per mile, depending on the pipeline type (inter- and intrastate) and diameter. **Table 3-7** shows the calculated unit costs for pipelines in Class 3 and Class 4 locations and Class 1 and Class 2 HCA locations, with estimates ranging from $20,600 to $168,600 per mile. PHMSA invites comments on the accuracy of these estimates.

Table 3-6. Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 1 and Class 2 Non-HCA Pipelines[1]

	Interstate Segment			Intrastate Segment		
	26" - 48"	14" - 24"	4" - 12"[2]	26" - 48"	14" - 24"	4" - 12"[2]
Diameter (inches)	30	16	8	30	16	8

[21] Updated to 2014 dollars using the Consumer Price Index.

Table 3-6. Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 1 and Class 2 Non-HCA Pipelines[1]

	Interstate Segment			Intrastate Segment		
	26" - 48"	14" - 24"	4" - 12"[2]	26" - 48"	14" - 24"	4" - 12"[2]
Pipe thickness (inches)	0.375	0.375	0.25	0.375	0.375	0.25
Segment Miles	60	60	60	30	30	30
Number of Mainline Valves	3	3	3	2	2	2
Number of Bends	3	3	3	3	3	3
Cost per Mainline Valve	$338,000	$220,000	$89,000	$338,000	$220,000	$89,000
Cost per Bend	$60,000	$32,000	$16,000	$60,000	$32,000	$16,000
Cost of Launcher	$741,000	$481,000	$280,000	$741,000	$481,000	$280,000
Cost of Receiver	$741,000	$481,000	$280,000	$741,000	$481,000	$280,000
Total Upgrade Cost[3]	$2,676,000	$1,718,000	$875,000	$2,338,000	$1,498,000	$786,000
Upgrade Costs per Mile	$44,600	$28,633	$14,583	$77,933	$49,933	$26,200
Gas Released per Mile (MCF)[4]	286	78	19	190	52	13
Cost of Gas Released per Mile[5]	$1,203	$327	$79	$802	$218	$53
Total Unit Cost (per mile)[6]	**$45,803**	**$28,960**	**$14,662**	**$78,735**	**$50,151**	**$26,253**

HCA = high consequence area
MCF = thousand cubic feet
1. Based on best professional judgment of PHMSA staff, and includes excavation, permitting, construction, and cleanup costs. Unit cost of gas released based on incident reports.
2. Pipelines below 4” generally cannot accommodate in-line inspection and will be exempt from requirements.
3. Total upgrade cost calculated as cost of launcher plus cost of receiver plus cost per bend multiplied by number of bends plus cost per mainline valve and number of mainline valves.
4. Based on Equation 1 using temperature (70 degrees F), pressure (14.7 PSIA at standard conditions; 50 PSI at blowdown conditions), and compressibility (factor of 0.88 at packed conditions) assumptions.
5. Assumes a natural gas cost of $4.21 per MCF, based on the cost of gas released intentionally during a controlled blowdown as part of a response to an incident (median of costs based on data for 294 incidents). Does not include the social cost of methane released.
6. Upgrade costs per mile plus cost of gas released during blowdown per mile.

Table 3-7. Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 3 and Class 4 Pipelines and Class 1 and Class 2 HCA Pipelines[1]

	Interstate Segment			Intrastate Segment		
	26" - 48"	14" - 24"	4" - 12"[2]	26" - 48"	14" - 24"	4" - 12"[2]
Diameter (inches)[2]	30	16	8	30	16	8
Segment Miles	45	45	45	15	15	15
Number of Mainline Valves	3	3	3	2	2	2
Number of Bends	6	6	6	6	6	6

Table 3-7. Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 3 and Class 4 Pipelines and Class 1 and Class 2 HCA Pipelines[1]						
	Interstate Segment			**Intrastate Segment**		
	26" - 48"	**14" - 24"**	**4" - 12"[2]**	**26" - 48"**	**14" - 24"**	**4" - 12"[2]**
Cost per Mainline Valve	$338,000	$220,000	$89,000	$338,000	$220,000	$89,000
Cost per Bend	$60,000	$32,000	$16,000	$60,000	$32,000	$16,000
Cost of Launcher	$741,000	$481,000	$280,000	$741,000	$481,000	$280,000
Cost of Receiver	$741,000	$481,000	$280,000	$741,000	$481,000	$280,000
Total Upgrade Cost[3]	$2,856,000	$1,814,000	$923,000	$2,518,000	$1,594,000	$834,000
Upgrade Costs per Mile	$63,467	$40,311	$20,511	$167,867	$106,267	$55,600
Gas Released per Mile (MCF)[4]	286	78	19	190	52	13
Cost of Gas Released per Mile[5]	$1,203	$327	$79	$802	$218	$53
Total Unit Cost (per mile)[6]	**$64,669**	**$40,638**	**$20,590**	**$168,668**	**$106,485**	**$55,653**

HCA = high consequence area
MCF = thousand cubic feet
PHMSA = Pipeline and Hazardous Materials Safety Administration
1. Based on best professional judgment of PHMSA staff, and includes excavation, permitting, construction, and cleanup costs. Unit cost of gas released based on incident reports.
2. Pipelines below 4” generally cannot accommodate in-line inspection and will be exempt from requirements.
3. Total upgrade cost calculated as cost of launcher plus cost of receiver plus cost per bend multiplied by number of bends plus cost per mainline valve and number of mainline valves.
4. Based on Equation 1 using temperature (70 degrees F), pressure (14.7 PSIA at standard conditions; 50 PSI at blowdown conditions), and compressibility (factor of 0.88 at packed conditions) assumptions.
5. Assumes a natural gas cost of $4.21 per MCF, based on the cost of gas released intentionally during a controlled blowdown as part of a response to an incident (median of costs based on data for 294 incidents). Does not include the social cost of methane released.
6. Upgrade cost plus cost per mile plus the cost of gas release per mile.

PHMSA used diameter data for interstate and intrastate gas transmission pipelines to calculate weighted average per-mile cost to upgrade segments to accommodate an ILI tool. **Table 3-8** shows these estimates.

Table 3-8. Calculation of Weighted Average Unit Cost to Accommodate Inline Inspection Tools					
	Pipeline Diameter			**Weighted Average Cost per Mile**	
Type	**> 26"[1]**	**14" - 24"[1]**	**<12"[1]**	**Class 1, 2, Non-HCA[2]**	**Class 3, 4, HCA[2]**
Interstate	41%	32%	27%	$31,930	$44,972
Intrastate	14%	29%	57%	$40,512	$86,176

1. Source: PHMSA 2014 Gas Transmission Annual Report
2. Based on Tables 3-6 and 3-7.

For comparison, some natural gas pipeline operators have provided information on costs to upgrade unpiggable pipelines to accommodate ILI, including Pacific Gas and Electric (PG&E; as

cited in American Gas Association (AGA), 2011; Appendix 2, Table 2-1) and Southern California Gas Company and San Diego Gas & Electric Company (SoCal, 2011; Table O). The information provided by PG&E indicates a unit cost of approximately $153,000 per mile, which is within the range calculated above for pipelines in Class 3 and Class 4 locations and Class 1 and Class 2 HCA locations. SoCal provided information on the cost to upgrade pre-1946 constructed mileage in Southern California.[22] The unit cost PHMSA calculated from the SoCal information ($4.4 million to $4.7 million per mile) may represent site-specific conditions that are not representative of the costs elsewhere and over a wide range of pipeline facilities.

According to INGAA (2015), factors affecting the unit costs include the location of the pipeline, type of labor (e.g., unionized versus nonunionized), what needs to be retrofitted (e.g., diameter changes in segment versus valve replacements), pipeline configuration, and pipe size. In response to a request for information from PHMSA, INGAA reported that unit costs to retrofit pipelines to accommodate ILI are highly variable, ranging from $50,000 to $1 million per mile (INGAA, 2015). Although the low end of this range is comparable to the costs shown above, the high end is considerably higher. However, PHMSA did not incorporate these cost estimates into the analysis since information is not available about the components and wider applicability of the costs, or is insufficient.

As described above, operators will have to blowdown a pipeline segment in order to safely make the necessary upgrades to permit a line to accept an inline inspection tool.

ILI

PHMSA assumed an operator would run three ILI tools per assessment consistent with its proposal for ILI assessments performed to re-establish MAOP in accordance with § 192.624. However, the use of three tools might not be required for an assessment conducted in accordance with § 192.710. In those cases, the estimate in **Table 3-9** might be high.

Table 3-9. Estimated Unit Cost of ILI

Component	Interstate (60-mile) Segment			Intrastate (30-mile) Segment		
	26" - 48"	14" - 24"	4" - 12"	26" - 48"	14" - 24"	4" - 12"
Mobilization[1]	$15,000	$12,500	$10,000	$15,000	$12,500	$10,000
Base MFL tool[2]	$90,000	$72,000	$54,000	$45,000	$36,000	$27,000
Additional combo tool (deformation & crack tools)	$45,000	$36,000	$27,000	$22,500	$18,000	$13,500
Reruns	$40,000	$30,000	$20,000	$40,000	$30,000	$20,000
Analytical and data integration services	$80,000	$80,000	$80,000	$40,000	$40,000	$40,000
Operator preparation[3]	$27,000	$23,050	$19,100	$16,250	$13,650	$11,050
Total	**$297,000**	**$253,550**	**$210,100**	**$178,750**	**$150,150**	**$121,550**

Source: PHMSA best professional judgment.
1. Mobilization is the cost for mobilization and demobilization of the construction work crew, material and equipment to and from the work site. Regional differences may apply.
2. Typically $900 to $1,500 per mile.

[22] Due to technical difficulties associated with SoCal's remaining unpiggable pipeline mileage, SoCal has elected to replace the pipes rather than retrofit to accommodate ILI. SoCal estimated replacement costs for pre-1946 pipeline segments using a cost matrix based on pipe diameter and length.

Table 3-9. Estimated Unit Cost of ILI						
	Interstate (60-mile) Segment			Intrastate (30-mile) Segment		
Component	26" - 48"	14" - 24"	4" - 12"	26" - 48"	14" - 24"	4" - 12"
3. Includes analysis, specifications, cleaning pigs, fatigue crack growth analysis, etc. Estimated as 10% of cost of ILI and related data analysis.						

As with the ILI upgrade cost PHMSA calculated a weighted average per mile cost based on annual report data on pipe diameter (**Table 3-10**).

Table 3-10. Estimation of ILI Assessment Cost[1]				
Segment Type	Less than 12" Diameter	14" - 24" Diameter	Greater than 26" Diameter	Weighted Average Cost Per Mile
Interstate (60-mile segment)	27%	32%	41%	$4,324
Intrastate (30-mile segment)	57%	29%	14%	$4,594
1. Weighted average based on unit costs (see Table 3-9) and percentages of gas transmission mileage by diameter for inter and intrastate pipe from the 2014 Gas Transmission Annual Report.				

Pressure Test

PHMSA used vendor pricing data to develop unit costs for pressure testing.[23] Pressure test costs can also vary substantially, especially with respect to the section length being tested. Costs also vary by diameter of pipe size.

Table 3-11. Estimated Cost of Conducting Pressure Test ($2015)				
Pipe Diameter (inches)	Segment Length (miles)			
	1	2	5	10
12	$156,550	$159,706	$191,114	$286,355
24	$197,528	$205,927	$344,057	$378,893
36	$304,680	$362,229	$486,555	$670,248
Source: Greene's Energy Group, LLC (2013), updated to 2015 dollars using the Bureau of Labor Statistics US All City Average Consumer Price Index (2013=233.5; 2015=237.8). Includes mobilization; safety training; equipment setup; fill and stabilize pipeline; 8-hour hydrostatic test; dewater pipeline with carbon media filtration; clean and dry pipeline; disassemble equipment; clean up and de-mobilize.				

PHMSA added the cost of gas lost during pressure testing using Equation 1. **Table 3-12** and **Table 3-13** show these calculations for interstate and intrastate pipelines respectively.

Table 3-12. Volume of Gas Lost During Pressure Tests (MCF): Interstate Pipelines[1]				
Pipe Diameter (inches)	Segment Length (miles)			
	1	2	5	10
12	48.1	96.2	240.4	480.9
24	192.3	384.7	961.7	1,923.4
36	432.8	865.5	2,163.9	4,327.7
MCF = thousand cubic feet				

[23] Greene's Energy Group, LLC (2013). Budgetary Proposal. Various 12", 24" & 36" Pipelines Located In Nashville, Tennessee. Prepared for PHMSA.

Table 3-12. Volume of Gas Lost During Pressure Tests (MCF): Interstate Pipelines[1]				
Pipe Diameter (inches)	Segment Length (miles)			
	1	2	5	10
1. Estimated using Equation 1.				

Table 3-13. Volume of Gas Lost During Pressure Tests (MCF): Intrastate Pipelines[1]				
Pipe Diameter (inches)	Segment Length (miles)			
	1	2	5	10
12	32.1	64.1	160.3	320.6
24	128.2	256.5	641.1	1,282.3
36	288.5	577.0	1,442.6	2,885.1
MCF = thousand cubic feet 1. Estimated using Equation 1.				

Table 3-14 and **Table 3-15** show the cost of lost gas based on the estimated volumes of lost gas and a cost of gas of $5.71 per thousand cubic feet.[24]

Table 3-14. Cost of Lost Gas: Interstate Pipelines[1]					
Pipe Diameter (inches)	Segment Length (miles)				
	1 Mile	2 Mile	5 Mile	10 Mile	Average
12	$275	$549	$1,373	$2,746	$1,236
24	$1,098	$2,197	$5,491	$10,983	$4,942
36	$2,471	$4,942	$12,356	$24,711	$11,120
1. Calculated based on volume lost (see Table 3-12) times the cost of gas ($5.71 per thousand cubic feet).					

Table 3-15. Costs of Lost of Gas: Intrastate Pipelines[1]					
Pipe Diameter (inches)	Segment Length (miles)				
	1 Mile	2 Mile	5 Mile	10 Mile	Average
12	$183	$366	$915	$1,830	$824
24	$732	$1,464	$3,661	$7,322	$3,295
36	$1,647	$3,295	$8,237	$16,474	$7,413
1. Based on volume lost (see Table 3-13) times the cost of gas ($5.71 per thousand cubic feet).					

Infrequently, there may be a need to establish a temporary gas supply while a pipeline is out of service for testing as backup for a test that takes longer than expected. This need could occur if there is no alternative source of gas supply and demand is high, and would be more likely to occur at the end of a system where there are not multiple feeds coming into the line. More alternatives are likely in highly populated areas. The need for temporary gas supplies is most often encountered by intrastate pipeline operators, and they generally avoid pressure testing in such situations if other assessment methods are available. When required, operators may have to construct temporary lines or establish temporary compressed natural gas plants to supply gas.

[24] EIA: 2014 U.S. Natural Gas Citygate Price (dollars per thousand cubic feet).

The cost of providing a temporary gas supply can be very high when needed. PHMSA estimated approximately $1 million per test and, in order to account for this potential cost, assumed approximately ten percent of pressure tests would necessitate temporary gas supplies. Thus, PHMSA included in the unit cost estimates an average of $100,000 per test to approximate the cost of providing temporary gas supplies (at a cost of $1 million for ten percent of tests). Given that pressure tests are applicable under the proposed rule primarily in more populated areas, this assumption may overstate costs.

Table 3-16 and **Table 3-17** show the resulting total estimated costs for pressure tests for inter and intrastate pipelines, respectively. **Table 3-18** shows these costs on a per mile basis.

Table 3-16. Total Pressure Test Assessment Cost: Interstate Pipelines

Component	Segment Length (miles)			
	1	2	5	10
12 inch				
Pressure test[1]	$273,963	$279,486	$334,449	$501,120
Lost gas[2]	$275	$549	$1,373	$2,746
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$374,237	$380,035	$435,822	$603,866
24 inch				
Pressure test[1]	$345,673	$360,372	$602,100	$663,063
Lost gas[2]	$1,098	$2,197	$5,491	$10,983
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$446,772	$462,568	$707,591	$774,046
36 inch				
Pressure test[1]	$533,190	$633,902	$851,471	$1,172,933
Lost gas[2]	$2,471	$4,942	$12,356	$24,711
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$635,661	$738,844	$963,826	$1,297,645

1. Unit costs (see Table 3-11) plus 75% multiplier to account for operator costs for engineering test plan, procurement of pipe materials, right of way and agent costs, manifold installation costs, engineering and operational oversight, right of way clean up, and return the line to service.
2. See Tables 3-14.
3. Approximation of cost of temporary supply (up to $1 million) for 10% of tests.

Table 3-17. Total Pressure Test Assessment Cost: Intrastate Pipelines

Component	Segment Length (miles)			
	1	2	5	10
12 inch				
Pressure test[1]	$273,963	$279,486	$334,449	$501,120
Lost gas[2]	$183	$366	$915	$1,830
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$374,146	$379,852	$435,364	$602,951

Table 3-17. Total Pressure Test Assessment Cost: Intrastate Pipelines				
Component	**Segment Length (miles)**			
	1	**2**	**5**	**10**
24 inch				
Pressure test[1]	$345,673	$360,372	$602,100	$663,063
Lost gas[2]	$732	$1,464	$3,661	$7,322
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$446,406	$461,836	$705,760	$770,385
36 inch				
Pressure test[1]	$533,190	$633,902	$851,471	$1,172,933
Lost gas[2]	$1,647	$3,295	$8,237	$16,474
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$634,837	$737,196	$959,708	$1,289,407
1. Unit costs (see Table 3-11) plus 75% multiplier to account for operator costs for engineering test plan, procurement of pipe materials, right of way and agent costs, manifold installation costs, engineering and operational oversight, right of way clean up, and return the line to service. 2. See Tables 3-15. 3. Approximation of cost of temporary supply (up to $1 million) for 10% of tests.				

Table 3-18. Per Mile Pressure Test Costs					
Pipe Diameter (inches)	**Segment Length (miles)**				
	1	**2**	**5**	**10**	**Average**
Interstate					
12	$373,963	$189,743	$86,890	$60,112	$177,677
24	$445,673	$230,186	$140,420	$76,306	$223,146
36	$633,190	$366,951	$190,294	$127,293	$329,432
Intrastate					
12	$374,146	$189,926	$87,073	$60,295	$177,860
24	$446,406	$230,918	$141,152	$77,039	$223,879
36	$634,837	$368,598	$191,942	$128,941	$331,079
Source: Tables 3-16 and 3-17 divided by miles per segment.					

To use these per mile cost estimates in the analysis, PHMSA calculated a weighted average cost based on the breakdown of gas transmission pipeline infrastructure by pipe diameter using size data from gas transmission annual reports (**Table 3-19**).

Table 3-19 Weighted Average Unit Pressure Test Assessment Cost Per Mile[1]				
Segment Type	**<12" Diameter**	**14"-34" Diameter**	**36"+ Diameter**	**Average Cost**
Interstate	27%	57%	15%	$226,939
Intrastate	57%	37%	6%	$203,556
1. Weighted average based on unit costs (see Table 3-18) and percentages of gas transmission mileage by diameter for inter and intrastate pipe from the 2014 Gas Transmission Annual Report.				

3.1.4.4 Estimation of Incremental Cost

Operators are already required to complete integrity management assessments of HCA segments under Subpart O of the Pipeline Safety Regulations. The MAOP re-verification tests required under the proposed rule would fulfil the operator's obligation to complete integrity management assessments. Therefore, estimation of incremental costs involves estimating total costs to re-establish MAOP, estimating baseline integrity management assessment costs, and subtracting to obtain incremental costs to re-establish MAOP.

<u>Total Cost to Re-establish MAOP</u>

To calculate total costs, PHMSA multiplied the estimated mileages by assessment method by the unit cost of assessments. In doing so, PHMSA used the 30-mile segment ILI unit costs for intrastate pipelines, and the 60-mile segment ILI unit costs for interstate segments. For pressure tests, PHMSA used the average cost across the one, two, five, and eight mile segment costs. PHMSA assumed that the assessments are equally distributed over the compliance period (i.e., 1/15th each year for 15 years). **Table 3-20** shows the results.

Table 3-20. Annual Costs to Re-establish MAOP, Previously Untested Pipe Operating at Greater than 30% SMYS in a HCA

Location	ILI	PT	Upgrade and ILI	Total
Interstate				
Class 1	$15,310	$42,321	$68	$57,699
Class 2	$5,175	$14,381	$228	$19,783
Class 3	$91,160	$270,169	$69,028	$430,356
Class 4	$59	$0	$43	$102
Subtotal	**$111,704**	**$326,870**	**$69,367**	**$507,940**
Intrastate				
Class 1	$1,986	$13,695	$4,670	$20,350
Class 2	$2,372	$34,064	$3,854	$40,291
Class 3	$71,285	$1,224,604	$340,745	$1,636,634
Class 4	$361	$7,227	$2,249	$9,837
Subtotal	**$76,004**	**$1,279,590**	**$351,518**	**$1,707,112**
Total				
Class 1	$17,296	$56,015	$4,738	$78,049
Class 2	$7,547	$48,445	$4,082	$60,074
Class 3	$162,445	$1,494,773	$409,773	$2,066,990
Class 4	$420	$7,227	$2,292	$9,939
Grand Total	**$187,708**	**$1,606,460**	**$420,884**	**$2,215,052**

ILI = inline inspection
HCA = high consequence area
MAOP = maximum allowable operating pressure
PT = pressure test
SMYS = specified minimum yield strength

<u>Baseline HCA Assessment Costs</u>

Baseline costs for integrity management assessments of HCA segments can be estimated based on historical assessment rates and the unit costs described in this section. In addition

to the test methods detailed previously, operators are currently permitted to use direct assessment methods.

Direct assessment (DA), or external corrosion direct assessment (ECDA), involves four distinct phases:

1. Pre-assessment data collection and analysis
2. Indirect inspection by walking along the top of the pipeline, inducing an electrical charge or signal in the steel pipe, and measuring the resulting signal
3. Excavation and direct examination of suspect locations identified by the indirect inspection
4. Post-assessment analysis of inspection and examination findings.

In the first phase, an operator must begin by integrating the historical knowledge of the pipeline, including facilities information, operating history, and the results of prior aboveground indirect examinations and direct examinations of the pipe, to assess the integrity of the pipe. In the second phase, the operator uses the primary and complementary indirect examinations to detect coating defects. The operator uses the results to find coating faults (damaged pipeline coating). For example, based on pipeline history, the operator may use the survey results to determine which coating faults are most likely to correspond to the severely corroded areas. Those areas where the potential for severe corrosion is highest should receive excavation priority. The third phase requires excavations to expose the pipe surface for metal-loss measurements, estimated corrosion growth rates, and measurements of corrosion morphology estimated during indirect examination. The goal of these excavations is to collect enough information to characterize the corrosion defects that may be present on the pipeline segment being assessed and validate the indirect examination methods. The operator should then determine the severity of all corrosion defects at the excavated coating fault areas using ASME B31G or a similar method to determine the safe operating pressure at the location. The final phase sets re-inspection intervals, provides a validation check on the overall ECDA process, and provides performance measures for integrity management programs. The re-inspection interval is a function of the validation and repair activity.

There is a potential range of cost associated with each phase. Cost is largely dependent on location, since the high cost of DA in urban and suburban areas includes traffic control and excavation permitting. PHMSA used BPJ to estimate the cost of each phase (**Table 3-21**) and used the mid estimate.[25] Unlike ILI or pressure testing, unit costs of performing DA are relatively independent of the length of the assessment segment.

Table 3-21 Estimated Unit Cost of Direct Assessment ($ per mile)

Phase	Low Estimate	Mid Estimate	High Estimate
Pre-assessment	$5,000	$7,500	$10,000
Indirect inspection	$2,500	$10,250	$18,000
Direct examination	$15,000	$17,500	$20,000

[25] "Rural Onshore Hazardous Liquid Low Stress Pipelines (Phase II)", Volume II, Jack Faucett & Associates, January, 2011

Table 3-21 Estimated Unit Cost of Direct Assessment ($ per mile)			
Phase	**Low Estimate**	**Mid Estimate**	**High Estimate**
Post-assessment	$5,000	$7,500	$10,000
Total	**$27,500**	**$42,750**	**$58,000**
Source: PHMSA best professional judgment			

Operators have used "other technology" to assess a relatively small amount of mileage. Although not required to report on the specific assessment method used, operators are required to submit notification to PHMSA prior to using other technology for assessments in HCAs. PHMSA reviewed 96 such notifications submitted by operators from 2004 through 2010; all related to the use or application of guided wave ultrasonic testing (GWUT). GWUT is used in special situations, such as at crossings where DA is difficult or problematic, and is often used to supplement a direct assessment. GWUT is similar to DA as it involves indirectly testing pipe to determine if further excavation and direct examination is needed. Like DA, a minimum of one or two excavations is required. Absent specific information about specific methods used, PHMSA assumed the unit costs for other assessments are similar to DA.

Operators report miles of integrity assessments in their annual report submissions. PHMSA summarized this data from 2010-2014 to estimate the proportion of periodic assessments using each methodology (**Table 3-22**).

Table 3-22. Integrity Assessment Methods			
Location	**Inline Inspection**	**Pressure Test**	**Direct Assessment and Other Methods**
Interstate	94%	5%	1%
Intrastate	56%	10%	34%
Source: 2010-2014 PHMSA Annual Report part F.			

As shown in Table 3-2, PHMSA estimated that 432 HCA miles will be tested on interstate pipeline miles and 476 will be tested on intrastate segments. **Table 3-23** shows the results of multiplying by the baseline integrity assessment method rates shown in Table 3-22.

Table 3-23. Estimated Annual Baseline Assessments of HCA Segments Operating at Greater than 30% SMYS				
Location	**Total HCA**	**ILI Miles**	**PT Miles**	**DA and Other Miles**
Interstate	28.8	27.2	1.3	0.3
Intrastate	31.8	17.8	3.2	10.8
HCA = high consequence area SMYS = specified minimum yield strength Source: Total mileage from Table 3-2 divided by 15 and multiplied by rates shown in Table 3-22.				

Table 3-24 shows the results of multiplying the mileage by the assessment unit costs.

Table 3-24. Estimated Baseline Costs Per Year on Previously Untested HCA Segments Operating at Greater than 30% SMYS				
Annual Cost	**Inline Inspections**	**Pressure Tests**	**Direct Assessment and**	**Total**

			Other Methods	
Interstate	$117,546	$297,063	$13,901	$428,511
Intrastate	$81,692	$643,795	$462,339	$1,187,826
Total	$199,239	$940,858	$476,239	$1,616,336

Net Annual Costs

The incremental costs of the proposed rule are the compliance costs net of baseline assessment costs (**Table 3-25)**.

Table 3-25. Net Average Annual Costs to Assess Previously Untested HCA Segments Operating at Greater than 30% SMYS

Component	Interstate	Intrastate	Total
Compliance costs	$507,940	$1,707,112	$2,215,052
Baseline integrity management costs	-$428,511	-$1,187,826	-$1,616,336
Net costs	**$79,430**	**$519,286**	**$598,716**

HCA = high consequence area
SMYS = specified minimum yield strength

3.1.5 ESTIMATION OF COMPLIANCE COSTS TO RE-ESTABLISH MAOP: INADEQUATE RECORDS

Topic Area 1 addresses the statutory requirement in the Act §23(c) which requires that PHMSA issue regulations for the operator to reconfirm MAOP for pipelines for which they do not have records substantiating the material properties of the pipe and the MAOP. Operator annual reports identify significant portions of gas transmission pipeline segments for which they do not have these records.

The Act requires that PHMSA require that MAOP be re-established as expeditiously as economically feasible; and determine what actions are appropriate for the pipeline owner or operator to take to maintain safety until a maximum allowable operating pressure is confirmed. Re-verification of MAOP in most cases would require an integrity assessment that meets specific requirements or equivalent. The assessment and testing requirements to re-establish MAOP are the same that apply to pipe that has not been previously tested (Section 3.1.4).

PHMSA used the following steps to estimate costs:

1. Estimate the mileage of pipe segments for which adequate documentation is lacking.
2. Estimate the breakdown of assessment methods.
3. Estimate the unit costs for conducting the assessments.
4. Estimate total incremental compliance cost.

3.1.5.1 Estimation of Mileage of Pipe for which Records are Inadequate

The proposed rule applies to pipe segments in HCAs and Class 3 and 4 locations. Operators report this data via annual reports required under Part 191. PHMSA used the mileage of pipeline segments (as reported by operators) for which there are not adequate records to support the existing MAOP previously established in accordance with 192.619. The

resulting estimate of pipe to which this mandate would apply is shown in **Table 3-26**.

Table 3-26. Mileage of Pipe for which Records are Inadequate

Location	HCA	Class 3 and Class 4 Non-HCA	Total
Interstate			
Class 1	79	0	79
Class 2	97	0	97
Class 3	437	672	1,109
Class 4	1	0.2	1
Subtotal	613	673	1,286
Intrastate			
Class 1	32	0	32
Class 2	34	0	34
Class 3	1,044	1,841	2,886
Class 4	125	1	126
Subtotal	1,235	1,843	3,077
Total			
Class 1	111	0	111
Class 2	130	0	130
Class 3	1,481	2,514	3,995
Class 4	125	2	127
Grand Total	**1,848**	**2,515**	**4,363**

HCA = high consequence area
Source: PHMSA 2014 Gas Transmission Annual Report: Part Q Sum of "Incomplete Records" columns by class location and HCA status

3.1.5.2 Estimation of Breakdown of Assessment Methods

PHMSA used the same method to estimate the breakdown of assessment methods as for previously untested pipe (Section 3.1.4.2) with the inclusion of non-HCA segments. Non-HCA segments have different piggability rates than HCA segments (**Table 3-27**), which therefore influences the assessment method mix. PHMSA assumed that the pressure test rates remain the same.

Table 3-27. Non-HCA Assessment Methods

Class Location	% ILI	Pressure Test	ILI Upgrade
Interstate			
Class 1	71%	5%	24%
Class 2	70%	5%	25%
Class 3	60%	5%	35%
Class 4	56%	0%	44%
Intrastate			
Class 1	53%	10%	37%
Class 2	40%	20%	40%
Class 3	33%	20%	47%

Table 3-27. Non-HCA Assessment Methods			
Class Location	**% ILI**	**Pressure Test**	**ILI Upgrade**
Class 4	62%	21%	17%
Source: Percent assessed with ILI based on 2014 Annual Report submissions on piggability. PHMSA assumed operators will use ILI where possible. Pressure test estimates PHMSA best professional judgment. PHMSA assumed the remainder will be upgraded to accept an ILI tool.			

3.1.5.3 Estimation of Unit Costs

PHMSA used the unit costs for ILI, pressure tests, and upgrading to accommodate ILI tools described in Section 3.1.4.3 for previously untested pipe.

3.1.5.4 Estimation of Total Incremental Cost

Similar to the method described in Section 3.1.4.4, estimation of incremental costs involves estimating total costs to re-establish MAOP, estimating baseline integrity management assessment costs, and subtracting to obtain incremental costs to re-establish MAOP.

Total Cost to Re-establish MAOP

To estimate total costs, PHMSA multiplied the estimated mileages by assessment method by the unit cost of assessments using the same method as for previously untested pipe (Section 3.1.4.4). PHMSA applied the assessment method ratios from Table 3-5 to HCA segments and the ratio from Table 3-18 for non-HCA segments. Again, PHMSA assumed that the assessments are equally distributed over the compliance period (i.e., 1/15th each year for 15 years). **Table 3-28** presents the results.

Table 3-28. Annual Costs to Re-establish MAOP, Segments with Inadequate Records Located in HCAs and Class 3 and 4 Non-HCAs				
Location	**ILI**	**PT**	**Upgrade and ILI**	**Total**
Interstate				
Class 1	$21,604	$59,718	$96	$81,418
Class 2	$26,307	$73,109	$1,158	$100,575
Class 3	$226,920	$839,240	$799,575	$1,865,734
Class 4	$216	$0	$363	$579
Subtotal	$275,047	$972,067	$801,192	$2,048,306
Intrastate				
Class 1	$6,331	$43,666	$14,889	$64,885
Class 2	$6,362	$91,356	$10,337	$108,055
Class 3	$341,079	$7,831,769	$3,373,390	$11,546,239
Class 4	$18,001	$359,107	$111,226	$488,334
Subtotal	$371,773	$8,325,898	$3,509,842	$12,207,513
Total				
Class 1	$27,935	$103,383	$14,985	$146,303
Class 2	$32,669	$164,465	$11,495	$208,630
Class 3	$567,999	$8,671,009	$4,172,965	$13,411,973
Class 4	$18,217	$359,107	$111,589	$488,913
Grand Total	**$646,820**	**$9,297,965**	**$4,311,034**	**$14,255,819**

Table 3-28. Annual Costs to Re-establish MAOP, Segments with Inadequate Records Located in HCAs and Class 3 and 4 Non-HCAs				
Location	ILI	PT	Upgrade and ILI	Total
ILI = inline inspection HCA = high consequence area MAOP = maximum allowable operating pressure PT = pressure test SMYS = specified minimum yield strength				

Baseline HCA Assessment Costs

Table 3-29 shows the results of multiplying by the assessment mileage by the baseline integrity assessment method rates.

Table 3-29. Estimated miles of HCA Segments with Inadequate MAOP Records Assessed per Year by Baseline Assessment Method				
Miles	Total HCA	ILI Miles	PT Miles	DA and Other Miles
Interstate	40.9	38.6	1.9	0.5
Intrastate	82.3	46.1	8.2	28.0
Source: HCA miles from Table 3-26 divided by 15 years and multiplied by the HCA assessment rates in Table 3-22.				

Table 3-30 shows the results of multiplying the mileage by the assessment unit costs.

Table 3-30. Estimated Annual Costs for Baseline Assessments of HCA Segments: Inadequate Records				
Location	Inline Inspections	Pressure Tests	Direct Assessment and Other Methods	Total
Interstate	$166,772	$421,466	$19,722	$607,959
Intrastate	$211,725	$1,668,550	$1,198,262	$3,078,537
Total	$378,497	$2,090,016	$1,217,984	$3,686,497

Net Annual Costs

The incremental costs of the proposed rule are the compliance costs net of baseline assessment costs (**Table 3-31**).

Table 3-31. Net Average Annual Costs to Assess HCA Segments: Inadequate Records			
Component	**Interstate**	**Intrastate**	**Total**
Compliance costs	$2,048,306	$12,207,513	$14,255,819
Baseline integrity management costs	-$607,959	-$3,078,537	-$3,686,497
Net costs	**$1,440,347**	**$9,128,976**	**$10,569,322**

3.1.6 ESTIMATION OF COMPLIANCE COSTS OF INTEGRITY ASSESSMENT FOR SEGMENTS OUTSIDE HCAS

PHMSA is proposing to require integrity assessments of pipeline in Class 3 and 4 MCAs and piggable pipelines in Class 1 and 2 MCAs within 15 years, and every 20 years thereafter. The proposed criteria for determining MCA locations would use the same process and the same

definitions as currently used to identify HCAs, except that the threshold for buildings intended for human occupancy and the threshold for persons that occupy other defined sites, that are located within the potential impact radius, would both be lowered from 20 to 5. The intention is that any pipeline location at which five or more houses or persons are normally expected to be located would be afforded extra safety protections.

In addition, as a result of the Sissonville, West Virginia incident, NTSB issued recommendation P-14-01, to revise the gas regulations to add principal arterial roadways including interstates, other freeways and expressways, and other principal arterial roadways as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures to the list of "identified sites" that establish a high consequence area. PHMSA proposes to meet the intent of NTSB's recommendation by incorporating designated interstates, freeways, expressways, and other principal four-lane arterial roadways into the MCA definition. The Sissonville, West Virginia incident location would not meet the current definition of an HCA, but would meet the proposed definition of an MCA.

Because significant non-HCA pipeline mileage has been previously assessed in conjunction with an assessment of HCA segments in the same pipeline, PHMSA also proposes to allow the use of those prior assessments for non-HCA segments provided that the assessment was conducted in conjunction with an integrity assessment required by subpart O. The proposed rule would also require that the assessment be conducted using the same methods as proposed for HCAs.

PHMSA used the following steps to estimate the cost of performing integrity assessments on select pipelines outside of HCAs:

1. Estimate the mileage of pipe subject to the proposed rule.
2. Estimate the mileage of applicable pipe not previously assessed.
3. Estimate the breakdown of assessment methods.
4. Estimate the unit costs of each assessment method.
5. Estimate total incremental compliance costs.

3.1.6.1 Estimation of Mileage of Pipe Subject to Proposed Rule

PHMSA has reliable information about pipeline mileage in class locations but does not have data on the pipeline mileage that would meet the MCA definition. PHMSA developed an estimate of the mileage that would meet the five home or occupied site criterion using annual report data and BPJ. Specifically, PHMSA used annual report data on mileage outside of HCAs and assumed that approximately 2% of Class 1, 50% of Class 2, and all Class 3 and 4 non-HCA mileage would meet the five home or occupied site MCA criteria. To the extent that this judgment over or understates applicable mileage, costs and benefits will be over or understated. There will be uncertainty regarding this factor until operators identify and report MCA mileage not previously assessed.

PHMSA used National Pipeline Mapping System data overlaid with Federal Highway Administration roadway maps to estimate the additional mileage in Class 1 and Class 2 locations that may overlap with interstates, freeways, expressways, and other principal four-lane arterial roadways. PHMSA estimated the PIR for this analysis based on the diameter of pipe. Diameter is optionally reported on NPMS submissions. For this analysis, PHMSA

applied an estimate of PIR based on diameter ranging from 150'-1000'. For unreported segment diameters, PHMSA used the highest PIR estimate. Based on this analysis, for illustration, PHMSA included 20% (2,240 miles out of 11,200 miles) as an estimate of the overlay mileage that would not already meet one of the other criteria for MCA or be located in an HCA. A sensitivity analysis provides a higher bound estimate. PHMSA invites comments on its estimate of mileage affected solely because of proximity to a highway.

Table 3-32 shows the resulting estimate of MCA mileage.

Table 3-32. Estimated MCA Mileage

	Onshore GT Miles[1]	Non-HCA[1,2]	MCA % of Non-HCA[3]	MCA Miles[4]	Roadway MCA Miles[5]	Total MCA Miles[6]
Interstate						
Class 1	160,381	159,374	2%	3,187	1,372	4,559
Class 2	17,811	16,774	50%	8,387	144	8,531
Class 3	13,925	7,378	100%	7,378	0	7,378
Class 4	29	10	100%	10	0	10
Subtotal	192,146	183,535	NA	18,962	1,516	20,478
Intrastate						
Class 1	72,254	71,692	2%	1,434	617	2,051
Class 2	12,820	12,396	50%	6,198	107	6,305
Class 3	19,726	10,224	100%	10,224	0	10,224
Class 4	880	156	100%	156	0	156
Subtotal	105,680	94,468	NA	18,011	724	18,735
Total						
Class 1	232,635	231,066	2%	4,621	1,989	6,610
Class 2	30,631	29,170	50%	14,585	251	14,836
Class 3	33,652	17,601	100%	17,601	0	17,601
Class 4	908	166	100%	166	0	166
Grand Total	**297,826**	**278,003**	**NA**	**36,973**	**2,240**	**39,213**

HCA = high consequence area
MCA = moderate consequence area
1. Source: PHMSA 2014 Gas Transmission Annual Report, Part Q. Total mileage shown for context only.
2. Excludes mileage reported under inadequate maximum allowable operating pressure records.
3. Source: PHMSA best professional judgment; based on homes and occupied sites in primary impact radius only.
4. Non-HCA mileage multiplied by percentage MCA.
5. 20% of total intersecting mileage. Total mileage based on overlay of Federal Highway Administration map with National Pipeline Mapping System pipeline data; 20% based on PHMSA best professional judgment.
6. MCA miles plus additional roadway MCA miles.

3.1.6.2 Estimation of Mileage Not Previously Assessed

The proposed rule would allow operators to use integrity assessments conducted for non-HCA pipe during the course of conducting HCA assessments to demonstrate compliance. Based on the overall reported assessed mileage and assessed mileage in HCAs, PHMSA assumed that 90 percent of non-HCA pipe in Class 4 locations has been assessed in this manner. Similarly, PHMSA assumed that 80 percent of MCA segments in Class 3 locations,

70 percent in Class 2 locations, and 50 percent in Class 1 locations have been assessed in conjunction with HCA assessments.

PHMSA assumed that all pipelines in MCAs that have previously been assessed in conjunction with an HCA assessment would be assessed again in the future within the proposed 15-year compliance period (in conjunction with the next HCA reassessment) for conducting an initial assessment and therefore there would not be a cost from the initial assessment requirement. Estimated MCA mileage not previously assessed would require initial assessment in accordance with proposed § 192.710. MCA segments located in Class 1 and Class 2 will only be subject to the assessment requirements if they are capable of accepting an ILI tool. **Table 3-33** summarizes the estimated incremental impact. Table 3-33 does not include overlap with previously estimated IVP requirements which would comply with integrity assessment requirements (see Section 3.1.7 below). Additionally, due to the location of launchers and receivers, operators may need to run the tools (pigs) for inline inspections through mileage that they are not required to assess (see Section 3.1.8 for a sensitivity analysis of this potential impact).

Table 3-33. Estimation of MCA Mileage Subject to Integrity Assessment Requirements

Location	MCA Mileage[1]	% Piggable[2]	Mileage Subject to Rule[3]	Mileage Subject to Rule less Overlap[4]	% MCA Currently Assessed[5]	MCA not Previously Assessed[6]
Interstate						
Class 1	4,559	72%	3,296	2,666	50%	1,333
Class 2	8,531	70%	5,935	5,397	70%	1,619
Class 3	7,378	NA	7,378	6,489	80%	1,298
Class 4	10	NA	10	10	90%	1
Subtotal	20,478	NA	16,619	14,562	NA	4,251
Intrastate						
Class 1	2,051	53%	1,086	1,009	50%	505
Class 2	6,305	40%	2,507	2,360	70%	708
Class 3	10,224	NA	10,224	9,500	80%	1,900
Class 4	156	NA	156	155	90%	15
Subtotal	18,735	NA	13,972	13,024	NA	3,128
Total						
Class 1	6,610	66%	4,382	3,676	50%	1,838
Class 2	14,836	57%	8,442	7,756	70%	2,327
Class 3	17,601	NA	17,601	15,990	80%	3,198
Class 4	166	NA	166	165	90%	16
Grand Total	**39,213**	**NA**	**30,591**	**27,587**	**NA**	**7,379**

MCA = moderate consequence area
1. See Table 3-24.
2. Assumed equal to non-HCA percent piggable based on data from Part R of the annual report (see Table 3-3).
3. MCA mileage times percent piggable.
4. Excludes MCA mileage subject to MAOP verification provisions
5. Assumed based on the overall reported assessed mileage and assessed mileage in HCAs
6. Mileage subject to proposed rule less overlap with previous other topic areas multiplied by (100%-% not previously assessed).

3.1.6.3 Estimation of Breakdown of Assessment Methods

The proposed rule would also require that the assessment be conducted using the same methods as proposed for HCAs. Because significant non-HCA pipeline mileage has been previously assessed in conjunction with an assessment of HCA segments in the same pipeline, PHMSA also proposes to allow the use of those prior assessments for non-HCA segments to comply with the new § 192.710, provided that the assessment was conducted in conjunction with an integrity assessment required by subpart O.

Using the same process as described in Section 3.1.4.2, PHMSA estimated the assessment methods to be deployed based on historical integrity management assessments **(Table 3-34)**. However, the proposed requirements under §192.710 allow assessments by any of the listed methods. Included in the allowed methods are direct assessment (DA) and other related technology. Direct assessment is not an allowed method for other Topic Area 1 requirements which focus on re-establishing MAOP under §192.624. Because DA is an allowed method, PHMSA assumed that operators would use DA in similar fashion as done to date under integrity management rules for HCAs. As a result of this difference, PHMSA did not assume that operators would upgrade pipelines that are not currently piggable, because DA is an option to assess unpiggable pipelines. **Table 3-35** shows the resulting estimates of mileage by assessment method.

Table 3-34. Estimated MCA Integrity Assessment Methods

Location	ILI[1]	PT[2]	DA and Other Methods[3]
Interstate			
Class 1	100%	0%	0%
Class 2	100%	0%	0%
Class 3	60%	5%	35%
Class 4	55%	5%	40%
Intrastate			
Class 1	100%	0%	0%
Class 2	100%	0%	0%
Class 3	33%	10%	57%
Class 4	62%	10%	28%

1. PHMSA assumed operators will use ILI where possible.
2. 2010-2014 PHMSA Annual Report part F. Historical rates of pressure testing in integrity assessments. The proposed rule requires assessment of pipelines in Class 1 and Class 2 locations only if piggable.
3. PHMSA assumed direct assessment of remaining pipelines.

Table 3-35. Estimated Assessment Methods for MCA Integrity Assessments (Miles)

	ILI	PT	DA & Other	Total
Interstate				
Class 1	1,333	0	0	1,333
Class 2	1,619	0	0	1,619
Class 3	773	59	466	1,298

Table 3-35. Estimated Assessment Methods for MCA Integrity Assessments (Miles)				
	ILI	**PT**	**DA & Other**	**Total**
Class 4	1	0	0	1
Subtotal	3,725	59	467	4,251
Intrastate				
Class 1	505	0	0	505
Class 2	708	0	0	708
Class 3	630	189	1,081	1,900
Class 4	10	2	4	15
Subtotal	1,852	191	1,085	3,128
Total				
Class 1	1,838	0	0	1,838
Class 2	2,327	0	0	2,327
Class 3	1,403	248	1,547	3,198
Class 4	10	2	5	16
Grand Total	**5,578**	**250**	**1,552**	**7,379**

Source: Based on Table 3-25 and Table 3-26.
DA = direct assessment
ILI = inline inspection
MCA = moderate consequence area
PT = pressure test

3.1.6.4 Estimation of Unit Costs

PHMSA used the unit costs for ILI and pressure testing, and direct assessment described above (see Section 3.1.4.3 and 3.1.4.5).

3.1.6.5 Estimation of Total Incremental Cost

Multiplying the estimated annual assessment mileages (total divided by 15 years, assuming that the assessments are equally distributed over the compliance period) by the unit costs results in the expected annual assessment costs. **Table 3-36** summarizes these results.

Table 3-36. Estimated Annual Costs for Expansion of Integrity Assessments Outside of HCAs				
	ILI	**PT**	**DA & Other**	**Total**
Interstate				
Class 1	$384,255	$0	$0	$384,255
Class 2	$466,647	$0	$0	$466,647
Class 3	$222,686	$891,819	$1,329,127	$2,443,632
Class 4	$161	$695	$1,161	$2,016
Subtotal	$1,073,748	$892,514	$1,330,288	$3,296,549
Intrastate				
Class 1	$145,469	$0	$0	$145,469
Class 2	$204,061	$0	$0	$204,061
Class 3	$181,620	$2,567,796	$3,080,114	$5,829,530

Table 3-36. Estimated Annual Costs for Expansion of Integrity Assessments Outside of HCAs				
	ILI	PT	DA & Other	Total
Class 4	$2,772	$20,892	$12,266	$35,929
Subtotal	$533,922	$2,588,687	$3,092,380	$6,214,989
Total				
Class 1	$529,723	$0	$0	$529,723
Class 2	$670,708	$0	$0	$670,708
Class 3	$404,306	$3,459,615	$4,409,241	$8,273,162
Class 4	$2,932	$21,586	$13,427	$37,946
Grand Total	**$1,607,669**	**$3,481,201**	**$4,422,668**	**$9,511,538**

DA = direct assessment
ILI = inline inspection
HCA = high consequence area
PT = pressure test

3.1.7 ESTIMATION OF COMPLIANCE COST TO RE-ESTABLISH MAOP FOR PREVIOUSLY UNTESTED PIPE OTHER THAN HCA GREATER THAN THIRTY PERCENT SMYS

NTSB issued two recommendations to PHMSA related to MAOP verification as a result of its investigation of the San Bruno incident. NTSB recommended that PHMSA amend 49 CFR § 192.619 to delete the exception and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test (Recommendation P-11-14) NTSB also recommended that PHMSA amend 49 CFR Part 192 so that manufacturing-related and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times MAOP (Recommendation P-11-15).

Section 3.1.4 addresses the proposed requirements that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test. In addition, the proposed rule would require re-establishing MAOP for previously untested pipe in the following categories:

- HCA operating at greater than 20 percent SMYS (greater than 30 percent SMYS is included above)
- Non-HCA within Class 3 and Class 4 locations
- MCA within Class 1 and Class 2 (piggable lines only).

The cost estimate for this requirement is structured as follows:

- Estimate the population of pipe segments to which the proposed requirements would apply.
- Estimate the breakdown of assessment methods expected to be deployed.
- Estimate the unit costs for each assessment method.
- Estimate total annual costs to achieve compliance by the deadlines specified in the proposed rule.

3.1.7.1 Estimation of Mileage of Previously Untested Pipe

Table 3-37, Table 3-38, and **Table 3-39** provide the estimated mileage of previously untested pipe in these categories. HCA mileage operated at between 20 and 30 percent SMYS is estimated as the total HCA mileage of previously untested pipe multiplied by the percent of mileage that operates between 20 and 30 percent of SMYS. Previously untested pipe outside of HCAs within Class 3 and 4 locations is reported by operators. Piggable previously untested MCA mileage in Class 1 and 2 locations is estimated by multiplying the estimated piggable MCA mileage by the percent of non-HCA mileage previously untested as reported by operators.

Table 3-37. Estimated Mileage of Previously Untested Pipe Operating at 20-30% SMYS in HCAs

Location	Previously Untested HCA Miles[1]	Percent of all Pipe Operating at 20-30% SMYS[1]	HCA Miles 20-30% SMYS[2]
Interstate			
Class 1	62	5%	3
Class 2	23	8%	2
Class 3	439	9%	41
Class 4	0	32%	0
Subtotal	524	NA	46
Intrastate			
Class 1	13	11%	1
Class 2	18	21%	4
Class 3	749	28%	213
Class 4	5	49%	3
Subtotal	786	NA	221
Total			
Class 1	75	7%	5
Class 2	41	14%	6
Class 3	1,189	21%	244
Class 4	6	48%	3
Grand Total	**1,310**	**NA**	**267**

HCA = high consequence area
SMYS = specified minimum yield strength
1. Source: 2014 PHMSA Gas Transmission Annual Report
2. Calculated as untested HCA mileage times percent of all pipe operated at 20-30% SMYS.

Table 3-38. Previously Untested Non-HCA Pipe in Class 3 and 4 Locations

Location	Mileage
Interstate	
Class 3	888
Class 4	0
Subtotal	888
Intrastate	

Table 3-38. Previously Untested Non-HCA Pipe in Class 3 and 4 Locations	
Location	**Mileage**
Class 3	724
Class 4	1
Subtotal	725
Total	
Class 3	1,612
Class 4	1
Grand Total	**1,613**
Source: 2014 PHMSA Gas Transmission Annual Report.	

Table 3-39. Estimation of Piggable MCA Mileage in Class 1 and 2 Locations			
Location	**Piggable MCA[1]**	**Percent of Non-HCA Mileage Previously Untested[2]**	**Previously Untested Piggable MCA Mileage[3]**
Interstate			
Class 1	3,296	19%	630
Class 2	5,935	9%	538
Subtotal	16,619	NA	1,168
Intrastate			
Class 1	1,086	7%	76
Class 2	2,507	6%	147
Subtotal	3,593	NA	223
Total			
Class 1	4,382		706
Class 2	8,442	NA	686
Grand Total	**12,824**	**NA**	**1,392**

MCA = moderate consequence area
1. Estimated as MCA (Table 3-24) times % piggable non-HCA (Table 3-3).
2. Source: 2014 PHMSA Gas Transmission Annual Report.
3. Calculated as piggable MCA mileage multiplied by percent untested non-HCA mileage.

Table 3-40 summarizes these mileages.

Table 3-40. Summary of Applicable Previously Untested Mileage				
Location	**HCA Operating at 20-30% SMYS**	**Class 3 and 4 Non-HCA**	**Piggable Class 1 and 2 MCA**	**Total**
Interstate				
Class 1	3	0	630	633
Class 2	2	0	538	540
Class 3	41	888	0	929
Class 4	0	0	0	0
Subtotal	46	888	1,168	2,103
Intrastate				
Class 1	1	0	76	78
Class 2	4	0	147	151

Table 3-40. Summary of Applicable Previously Untested Mileage				
Location	**HCA Operating at 20-30% SMYS**	**Class 3 and 4 Non-HCA**	**Piggable Class 1 and 2 MCA**	**Total**
Class 3	213	724	0	937
Class 4	3	1	0	4
Subtotal	221	725	223	1,169
Total				
Class 1	5	0	706	711
Class 2	6	0	686	691
Class 3	254	1,612	0	1,866
Class 4	3	1	0	4
Grand Total	**267**	**1,613**	**1,392**	**3,272**
Source: See Tables 3-30, 3-31, and 3-32. HCA = high consequence area MCA = moderate consequence area SMYS = specified minimum yield strength				

3.1.7.2 Estimation of Breakdown of Assessment Methods

For mileage in HCAs operating at greater than 20 percent SMYS and non-HCA within Class 3 and Class 4 locations, PHMSA applied the assessment method ratios described in Section 3.1.6.3 to all non-MCA mileage within this part. For the remainder (piggable pipe in MCA Class 1 and 2 locations), PHMSA assumed 100% of these miles will be inspected via ILI. **Table 3-41** shows the results (see **Appendix A** for details).

Table 3-41. Miles by Estimated Assessment Method				
Location	**Total ILI**	**PT**	**Upgrade and ILI**	**Total**
Interstate				
Class 1	633	0	0	633
Class 2	540	0	0	540
Class 3	466	38	259	763
Class 4	0	0	0	0
Subtotal	1,639	38	259	1,937
Intrastate				
Class 1	77	0	0	78
Class 2	150	1	1	151
Class 3	261	130	258	649
Class 4	2	1	1	3
Subtotal	490	131	259	880
Total				
Class 1	710	0	0	711
Class 2	690	1	1	691
Class 3	728	168	516	1,412
Class 4	2	1	1	3
Grand Total	**2,129**	**170**	**518**	**2,817**

3.1.7.3 Estimation of Unit Costs

PHMSA used the unit costs as developed in Section 3.1.4.3.

3.1.7.4 Estimation of Total Incremental Cost

Similar to the method described in Section 3.1.4.4, estimation of incremental costs involves estimating total costs to re-establish MAOP, estimating baseline integrity management assessment costs, and subtracting to obtain incremental costs to re-establish MAOP.

<u>Total Cost to Re-establish MAOP</u>

To estimate total costs, PHMSA multiplied the estimated mileages by assessment method by the unit cost of assessments using the same method as for previously untested pipe (Section 3.1.4.4). Multiplying the estimated annual assessment mileages (total divided by 15 years, assuming that the assessments are equally distributed over the compliance period) by the unit costs results in the expected annual assessment costs summarized in **Table 3-42** shows the results.

Table 3-42. Annual Costs to Re-establish MAOP, Previously Untested Segments Other than HCA Operating at Greater than 30% SMYS

Location	ILI	PT	Upgrade and ILI	Total
Interstate				
Class 1	$182,419	$2,317	$4	$184,740
Class 2	$155,703	$1,381	$22	$157,106
Class 3	$134,370	$577,245	$775,775	$1,487,390
Class 4	$35	$0	$25	$60
Subtotal	$472,527	$580,943	$775,826	$1,829,296
Intrastate				
Class 1	$22,249	$2,015	$687	$24,952
Class 2	$43,135	$10,339	$1,170	$54,644
Class 3	$75,330	$1,760,636	$772,369	$2,608,335
Class 4	$450	$8,626	$2,489	$11,565
Subtotal	$141,165	$1,781,616	$776,715	$2,699,495
Total				
Class 1	$204,669	$4,332	$691	$209,692
Class 2	$198,838	$11,720	$1,192	$211,749
Class 3	$209,700	$2,337,880	$1,548,144	$4,095,725
Class 4	$485	$8,626	$2,514	$11,625
Grand Total	**$613,692**	**$2,362,558**	**$1,552,541**	**$4,528,791**

ILI = inline inspection
HCA = high consequence area
MAOP = maximum allowable operating pressure
PT = pressure test
SMYS = specified minimum yield strength

<u>Baseline High Consequence Area Assessment Costs</u>

Table 3-x shows the results of multiplying by the assessment mileage by the baseline

integrity assessment method rates.

Table 3-43. Estimated Miles of Previously Untested HCA Segments Operating at 20%-30% SMYS Assessed per Year by Baseline Assessment Method

Location	Total HCA	Inline Inspection	Pressure Test	Direct Assessment and Other Methods
Interstate	3.1	2.9	0.1	0.03
Intrastate	14.7	8.2	1.5	5.0

HCA = high consequence area
SMYS = specified minimum yield strength
Source: HCA mileage from Table 3-30 divided by 15 and multiplied by the baseline HCA assessment rates from Table 3-22

PHMSA multiplies this mileage by the assessment unit costs to estimate the cost to complete HCA baseline integrity management assessments on HCA mileage in this section **(Table 3-44).**

Table 3-44.Estimated Baseline Costs Per Year on HCA Segments Operating at 20%-30% SMYS Assessed per Year by Baseline Assessment Method

Location	Inline Inspections	Pressure Tests	Direct Assessment and Other Methods	Total
Interstate	$12,558	$31,736	$1,485	$45,779
Intrastate	$37,889	$298,598	$214,437	$550,924
Total	**$50,447**	**$330,334**	**$215,922**	**$596,703**

Net Annual Costs

The incremental costs of the proposed rule are the compliance costs net of baseline assessment costs (**Table 3-45**).

Table 3-45. Net Average Annual Costs to Assess HCA Segments Operating at 20-30% Specified Minimum Yield Strength

Component	Interstate	Intrastate	Total
Compliance costs	$1,829,296	$2,699,495	$4,528,791
Baseline integrity management costs	-$45,779	-$550,924	-$596,703
Net costs	**$1,783,517**	**$2,148,571**	**$3,932,088**

3.1.8 SOCIAL COST OF METHANE DUE TO BLOWDOWN EMISSIONS

As noted above**Error! Reference source not found.**, upgrading pipelines to accommodate ILI and pressure testing pipelines will entail the release of natural gas into the atmosphere via a blowdown procedure. Natural gas is comprised primarily of methane (**Table 3-46**), a potent GHG. PHMSA used estimates of the social cost of methane (SCM) that were developed by Marten et al., (2014) to value these emissions. See Appendix B for discussion and annual values.

Table 3-46. Natural Gas Composition

Gas	Percent of Volume
Methane (CH_4)	95.7%

Table 3-46. Natural Gas Composition	
Gas	**Percent of Volume**
Carbon dioxide ($C0_2$)	1.3%
Other Fluids	3.0%
Source: Estimated based on natural gas quality standards and operator reported measurements Enbridge Estimates: https://www.enbridgegas.com/gas-safety/about-natural-gas/components-natural-gas.aspx Spectra Estimates: https://www.uniongas.com/about-us/about-natural-gas/Chemical-Composition-of-Natural-Gas	

3.1.8.1 Emissions from Pressure Testing

Pressure testing will involve emptying the segment of natural gas. PHMSA used annual report data on gas transmission pipeline diameter (**Table 3-47**) and estimates of natural gas emissions per mile due to pressure test blowdowns by segment diameter (**Table 3-48**) to calculate a weighted average estimate of emissions per mile for pressure tests in interstate and intrastate segments. **Table 3-49** presents these greenhouse gas emissions per mile.

Table 3-47. Proportion of Gas Transmission Mileage by Diameter			
Segment Type	**<12" Diameter**	**14"-34" Diameter**	**36"+ Diameter**
Interstate	27%	57%	15%
Intrastate	57%	37%	6%
Source: 2014 Gas Transmission Annual Report			

Table 3-48. GHG Emissions from Pressure Test Blowdowns			
Diameter (inches)	**Gas Released (MCF)**	**Methane (MCF)**	**Carbon Dioxide (lbs)**
12	113	108	168
24	424	406	631
36	974	932	1,449
Source: See Equation 1 and Table 3-46 lbs = pounds MCF = thousand cubic feet			

Table 3-49. GHG Emissions from Pressure Tests per Assessment Mile			
Location	**Gas Released per mile (MCF)**	**Methane Released per Mile (MCF)**	**Carbon Dioxide Released per Mile (lbs)**
Interstate	418	400	622
Intrastate	280	268	416
lbs = pounds MCF = thousand cubic feet 1. Weighted average based on share of pipeline mileage by diameter.			

PHMSA then multiplied these values by the estimates of miles assessed by pressure tests in Section 3.1 to calculate emissions for each subtopic of Topic Area 1. The results are shown in **Table 3-50** below.

Table 3-50. Total GHG Emissions from Pressure Test Blowdowns

Item	PT Miles (Interstate)	PT Miles (Intrastate)	Gas Released (MCF)	Methane (MCF)	Carbon Dioxide (lbs)
Re-establish MAOP: HCA > 30% SMYS	2[1]	47[1]	13,930	13,331	20,717
Re-establish MAOP: Inadequate Records	36[2]	566[2]	173,576	166,112	258,142
Integrity Assessment: Non-HCA	59[1]	191[1]	78,037	74,682	116,057
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	36[1]	109[1]	45,754	43,787	68,045
Total	**134**	**913**	**311,297**	**297,911**	**462,961**

PT = pressure test
MCF = thousand cubic feet
1. Miles pressure tested for compliance with MAOP reverification requirements minus baseline HCA pressure test miles
2. MCA miles pressure tested for compliance with MCA integrity assessment requirements

3.1.8.2 Emissions from ILI Upgrade

Operators will also need to blowdown segments in order to make the necessary upgrades to permit a line to accept an inline inspection tool. Besides the new emissions estimate and a different breakdown of mileage by diameter, the analysis proceeds identically as for the estimate for blowdowns due to pressure testing. **Table 3-51** provides the estimated volume of gas released during ILI upgrades based on Equation 1. **Table 3-52** provides the proportion of gas transmission mileage by diameter, which is used to calculate the weighted average volume of gas released per ILI upgrade mile.

Table 3-51. Natural Gas Lost due to Blowdowns per Mile (MCF/Mile)

Location	Diameter 12" or less	Diameter 14" to 24"	Diameter 26" and above
Interstate	19	78	286
Intrastate	13	52	190

MCF = thousand cubic feet
Source: See Equation 1 in Section 3.1.4.3

Table 3-52. Proportion of Gas Transmission Mileage by Diameter

Segment Type	≤ 12” Diameter	14"-24" Diameter	≥ 26"Diameter
Interstate	27%	32%	41%
Intrastate	57%	29%	14%

Source: 2014 Gas Transmission Annual Reports

Table 3-53 provides the estimate for emissions per mile due to upgrade related blowdowns.

Table 3-53. GHG Emissions from Blowdowns, ILI Upgrade (per Mile)

Location	Gas Released (MCF)[1]	Methane Emissions (MCF)[2]	$C0_2$ Emissions (lbs)[3]
Interstate	147	140	218

Intrastate	49	47	73

CO_2 = carbon dioxide
GHG = greenhouse gas
HCA = high consequence area
ILI = inline inspection
lbs = pounds
MCF = thousand cubic feet
1. Weighted average based on natural gas emissions due to upgrade by diameter and annual report diameter data.
2. Gas emissions multiplied by 95.7% methane.
3. Gas emissions multiplied by 1.3% $C0_2$ and 114.4 lbs/MCF $C0_2$.

Table 3-54 summarizes total greenhouse gas emissions due to blowdowns for ILI upgrade are summarized in

Table 3-54. Total GHG Emissions due to Blowdowns

Item	ILI Upgrade Miles (Interstate)	ILI Upgrade Miles (Intrastate)	Gas Released (MCF)	Methane Emissions (MCF CH_4)	$C0_2$ Emissions (lbs)
Re-establish MAOP: HCA > 30% SMYS	23	118	42,817	40,975	63,677
Re-establish MAOP: Inadequate Records	267	1,174	440,285	421,353	654,792
Integrity Assessment: Non-HCA	0	0	0	0	0
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	259	259	180,781	173,008	268,858
Total	**549**	**1,552**	**663,883**	**635,336**	**987,327**

CO_2 = carbon dioxide
CH_4 = methane
GHG = greenhouse gas
HCA = high consequence area
ILI = inline inspection
MAOP = maximum allowable operating pressure
MCF = thousand cubic feet
SMYS = specified minimum yield strength

3.1.8.3 Total Emissions

PHMSA assumed that the assessment rate is the same for each year of the assessment period. Therefore, emissions per year are calculated as the total divided by 15 (**Table 3-55**).

Table 3-55. Total Emissions Per Year

Item	Gas Released (MCF)	Methane Emissions (MCF CH_4)	$C0_2$ Emissions (lbs)
Re-establish MAOP: HCA > 30% SMYS	3,783	3,620	5,626
Re-establish MAOP: Inadequate Records	40,924	39,164	60,862
Integrity Assessment: Non-HCA	5,202	4,979	7,737

Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	15,102	14,453	22,460
Total	**65,012**	**62,216**	**96,686**

CO_2 = carbon dioxide
CH_4 = methane
HCA = high consequence area
lbs = pounds
MAOP = maximum allowable operating pressure
MCF = thousand cubic feet
SMYS = specified minimum yield strength

3.1.8.4 Summary of Estimated Environmental Costs

PHMSA used the estimates of SCM described in Appendix B to value the costs associated with the estimated emissions. **Table 3-56** shows these results.

Table 3-56. Average Annual Social Cost of Gas Lost due to Blowdown (Millions 2015$)

Topic Area 1 Scope	Average Annual Methane Lost from Blowdown (MCF)			Average Annual Social Cost [1]
	ILI Upgrade	Pressure Test	Total	
Previously untested in HCA	2,854	929	3,620	$0.11
HCA and Class 3 and 4 with inadequate records	29,352	11,572	39,164	$1.15
Applicable MCA	0	5,202	4,979	$0.15
Previously other HCA and non-HCA	12,052	3,050	14,453	$0.43
Subtotal	44,259	20,753	62,216	$1.83

MCF = thousand cubic feet
1. Based on the values for social cost of methane and social cost of carbon calculated using a 3% discount rate (see Appendix B).

3.1.9 SUMMARY AND SENSITIVITY ANALYSES

Table 3-57 provides the present value of costs over the study period for Topic Area 1.

Table 3-57. Present Value Costs Discounted at 7%, Topic Area 1 (Millions 2015$)[1]

Scope	Total			Average Annual		
	Compliance Cost	Social Cost of GHG Emissions	Total Cost	Annual Compliance Cost	Annual Social Cost of GHG Emissions	Average Annual Cost
Re-establish MAOP: HCA > 30% SMYS	$5.8	$1.6	$7.4	$0.4	$0.1	$0.5
Re-establish MAOP: Inadequate Records	$103.0	$17.3	$120.3	$6.9	$1.2	$8.0
Integrity Assessment: Non-HCA	$92.7	$2.2	$94.9	$6.2	$0.1	$6.3

Table 3-57. Present Value Costs Discounted at 7%, Topic Area 1 (Millions 2015$)[1]

Scope	Total			Average Annual		
	Compliance Cost	Social Cost of GHG Emissions	Total Cost	Annual Compliance Cost	Annual Social Cost of GHG Emissions	Average Annual Cost
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	$38.3	$6.4	$44.7	$2.6	$0.4	$3.0
Total	**$239.9**	**$27.5**	**$267.3**	**$16.0**	**$1.8**	**$17.8**

GHG = greenhouse gas
HCA = high consequence area
MAOP = maximum allowable operating pressure
SMYS = specific minimum yield strength
1. Total is of the 15 year compliance period; average annual is total divided by 15.

Table 3-58. Present Value Costs Discounted at 3%, Topic Area 1 (Millions 2015$)[1]

Scope	Total			Average Annual		
	Compliance	Social Cost of GHG Emissions	Total	Compliance	Social Cost of GHG Emissions	Total
Re-establish MAOP: HCA > 30% SMYS	$7.4	$1.6	$9.0	$0.5	$0.1	$0.6
Re-establish MAOP: Inadequate Records	$130.0	$17.3	$147.2	$8.7	$1.2	$9.8
Integrity Assessment: Non-HCA	$117.0	$2.2	$119.2	$7.8	$0.1	$7.9
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	$48.3	$6.4	$54.7	$3.2	$0.4	$3.6
Total	**$302.6**	**$27.5**	**$330.1**	**$20.2**	**$1.8**	**$22.0**

HCA = high consequence area
MAOP = maximum allowable operating pressure
SMYS = specific minimum yield strength
1. Total is of the 15 year compliance period; average annual is total divided by 15.

These cost estimates are subject to uncertainty with respect to estimated mileages and the unit costs for integrity assessment methods.

As a practical matter, ILI is conducted in a continuous segment between tool launcher and

receiver facilities. Launchers and receivers are already in place, typically located at compressor stations spaced 20 to 50 miles apart, for much of the mileage that will be identified as MCAs under the proposed rule. Some of this has already been assessed as reflected in the analysis. However, PHMSA does not have locational data on previously unassessed pipeline that would be classified as MCA under the proposed rule and the location of launchers and receivers along this pipeline to estimate any additional non-MCA mileage that would be assessed. Therefore, PHMSA did not include costs (or benefits) for assessing additional mileage that is not required to be assessed under the proposed rule.

PHMSA invites comments and data on the extent of such mileage. Absent such data, PHMSA conducted a sensitivity analysis of the estimated costs to additional ILI mileage by applying a factor to all ILI mileage. **Table 3-59** shows the results for a doubling of ILI mileage, which results in an approximately 11percent increase in costs. A tripling of ILI mileage results in an approximately 22 percent increase in costs.

Table 3-59. Present Value Costs, Topic Area 1: ILI Miles Doubled (Millions 2015$)

Scope	7% Discount Rate		3% Discount Rate	
	Total	Average Annual	Total	Average Annual
Re-establish MAOP: HCA > 30% SMYS	$9.3	$0.6	$11.3	$0.8
Re-establish MAOP: Inadequate Records	$126.6	$8.4	$155.2	$10.3
Integrity Assessment: MCA	$110.6	$7.4	$138.9	$9.3
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; MCA Class 1 and 2	$50.7	$3.4	$62.3	$4.2
Total	**$297.1**	**$19.8**	**$367.7**	**$24.5**

HCA = high consequence area
ILI = inline inspection
MAOP = maximum allowable operating pressure
SMYS = specific minimum yield strength

Occasionally operators will have to provide alternative gas supplies during pressure tests if the line is the sole source of gas for a community. This situation could influence the cost of completing a pressure test. PHMSA assumed that 10% of pressure tests will require alternative gas supplies If this rate is reduced to zero, present value costs for Topic Area 1 fall 11% ($15.9 million average annual and $ 238.9 million total at a 7% discount rate; $19.6 million average annual and $294.3million total at a 3% discount rate). Note that these additional assessments would also result in benefit associated with averting incidents (safety and GHG emission reductions).

Another source of uncertainty is the extent to which gas transmission pipeline PIRs overlap with highway right-of-ways. Section 3.1.6 uses an illustration of 20% of such mileage not meeting other MCA or HCA criteria. PHMSA calculated a highest cost estimate assuming that 89% of pipeline mileage conflicting with highway right-of-way (9,912 miles). This percentage is equivalent to the percent of all gas transmission miles located in Class 1 and Class 2 locations. In this scenario, annual average present value compliance costs using a 7

percent discount rate would rise from $17.8 to $18.3 million, an increase of approximately 3% ($22.0 to $22.7 million using a 3 percent discount rate). Benefits would likely rise proportionally, however the overall impact of this assumption is small.

An additional alternative for highway mileage costs would be to calculate a weighted average of pipeline-highway overlap mileage for the unreported diameters based on rates for the reported diameter segments rather than conservatively applying the highest PIR estimates. Using this method the total overlap mileage falls from 11,200 to approximately 8,400, reducing mileage by 25%. Compared to the 20% scenario in the base analysis, this change causes average annual present value costs to fall by less than $50,000 a year in either the 7% or 3% discount rate scenarios.

3.2 INTEGRITY MANAGEMENT PROGRAM (IMP) PROCESS CLARIFICATIONS

Topic Area 2 includes the following clarifications to the IM regulations in 49 CFR Part 192, Subpart O:

1. Clarify management of change (MoC) process requirements for operator IM programs [§ 192.911]
2. Clarify threat identification requirements for time-dependent threats [§ 192.917]
3. Clarify requirements related to baseline assessment methods [§ 192.921]
4. Clarify (and in limited cases, revise) repair criteria for remediating defects discovered in HCA segments
5. Clarify preventive and mitigative (P&M) measures based on risk assessments, to include more examples such as correcting root causes of past incidents [§ 192.935(a)]
6. Clarify P&M measures for covered segments for outside force damage [§ 192.935(b)]
7. Clarify requirements for periodic evaluations and assessments, including some specifically for plastic transmission pipelines [§ 192.937]
8. Written notification for a 6-month extension of 7-yr reassessment interval [§ 192.939]

3.2.1 PROBLEM STATEMENT

Title 49 CFR Part 192, Subpart O prescribes requirements for managing pipeline integrity in defined HCAs. Following the San Bruno incident, the NTSB recommended that PG&E assess every aspect of its IM program, paying particular attention to the areas identified in the incident investigation. PHMSA also analyzed the issues related to information analysis and risk assessment that the NTSB identified in its investigation. PHMSA held a workshop on July 21, 2011 to address perceived shortcomings in the implementation of IM risk assessment processes and the information and data analysis (including records) upon which such risk assessments are based. PHMSA sought input from stakeholders on these issues, and determined that additional clarification and specificity is needed for existing performance-based rules.

The proposed rule clarifies the performance-based risk assessment aspects of the IM rule to specify that operators perform risk assessments that are adequate to:

- Evaluate the effects of interacting threats
- Determine additional preventive and mitigative measures needed
- Analyze how a potential failures could affect HCAs, including the consequences of the entire worst-case incident scenario from initial failure to incident termination
- Identify the contribution to risk of each risk factor, or each unique combination of risk factors that interact or simultaneously contribute to risk at a common location
- Account for, and compensate for, uncertainties in the model and the data used in the risk assessment
- Evaluate risk reduction associated with candidate activities such as preventive and mitigative measures.

The proposed rule would also expand on, and provide more specificity for, conducting integrity assessments and remediating anomalies found as a result of those assessments.

3.2.2 ASSESSMENT OF REGULATORY IMPACT

These clarifications, with a few limited exceptions, would not alter, change or revise the requirements of Subpart O. As such, they would not represent changes that would be expected to result in measurable costs to pipeline operators (with a few exceptions, which are explicitly identified and for which PHMSA performed a cost analysis). The information presented in this section describes the basis for this conclusion for each of the proposed revisions to Subpart O.

Management of Change

49 CFR § 192.911(k) requires that IM programs include a management of change process as outlined in ASME/ANSI B31.8S, Section 11. PHMSA has determined that more specific attributes of the MoC process should be codified within the text of § 192.911(k). The proposed rule would amend § 192.911(k) to specify that the MoC process must include the reasons for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. These attributes are already required by reference to ASME B31.8S as if they were set out in the rule in full (see §192.7(a)). Since these are not new requirements, PHMSA concluded that this requirement would not impose an additional cost burden on pipeline operators.

Threat Identification Requirements

49 CFR § 192.917(b) requires data gathering and integration requirements as part of an effective IM program. Data gathering and integration is an important element of good IM practices. Accordingly, the proposed rule would include specific performance-based requirements for collecting, validating, and integrating pipeline data. These would add specificity to the data integration language, list a number of pipeline attributes that must be included in these analyses, explicitly require that operators integrate analyzed information, and ensure data is verified and validated.

The proposed rule would also require operators to use validated, objective data to the maximum extent practical. To the degree that subjective data from SMEs must be used, PHMSA requires that operator programs include specific features to compensate for SME bias. These attributes are already required by reference to ASME B31.8S, Section 4, as if they were set out in the rule in full (see §192.7(a)).

49 CFR § 192.917(c) requires operators to perform risk assessment as part of an effective IM program. The proposed rule would clarify that operators must perform risk assessments that address worst case scenarios and that are capable of accounting for uncertainties and quantifying risk-reduction alternatives. In addition, in response to NTSB Recommendation P-11-18, the proposed rule would add performance-based language to require that operators validate their risk models in light of incident, leak, and failure history, and other historical information. The proposed rule would also clarify that operators use the risk assessment to establish and implement adequate operations and maintenance processes, and establish and deploy adequate resources for successful execution of activities, processes, and systems associated with operations, maintenance, preventive measures, mitigative measures, and managing pipeline integrity.

In accordance with §§ 192.917(b) and 192.917(c), these attributes of data gathering and integration, and risk assessment, are already required by reference to ASME B31.8S, Sections 4 and 5, as if they were set out in the rule in full (see §192.7(a)). Therefore, this requirement would not impose an additional cost burden on pipeline operators.

<u>Baseline Assessment Methods</u>
49 CFR § 192.921 requires that pipelines subject to IM rules have an integrity assessment. Current rules allow the use of ILI, PT in accordance with 49 CFR Part 192, Subpart J, DA for the threats of external corrosion, internal corrosion, and SCC, and other technology that the operator demonstrates provides an equivalent level of understanding of the condition of the pipeline.

Following the San Bruno incident PHMSA determined that baseline assessment methods should be revised to emphasize ILI and PT over direct assessment. For the failed San Bruno pipeline, PG&E relied heavily on DA under circumstances for which it is not effective. Further, ongoing research and industry response to the ANPRM[26] appears to indicate that stress corrosion cracking direct assessment (SCCDA) is not as effective and does not provide an equivalent understanding of pipe conditions with respect to stress corrosion cracking defects as ILI or hydrostatic pressure testing at test pressures exceeding those required by 49 CFR Part 192, Subpart J (i.e., "spike" hydrostatic pressure test). Therefore, the proposed rule would require that DA only be allowed when the pipeline cannot be assessed using ILI. As a practical matter, DA is typically not chosen as the assessment method if the pipeline can be assessed using ILI. Therefore, this requirement would not impose a significant additional cost burden on pipeline operators.

The proposed rule would also add three assessment methods:

1. A "spike" hydrostatic pressure test, which is particularly well suited to address stress corrosion cracking and other cracking or crack-like defects;

[26] *Ibid*. 4

2. Guided Wave Ultrasonic Testing (GWUT), which is particularly appropriate in cases where short segments such as road or railroad crossings are difficult to assess; and
3. Excavation with direct *in situ* examination.

All of these assessment methods are implicitly allowed by existing requirements; the proposed rule would not mandate use.

GWUT is “other technology” under existing rules, and operators must notify PHMSA prior to its use. PHMSA has developed guidelines for the use of GWUT, which have proven successful, and incorporated them into the proposed rule. As such, future notifications would not be required, representing a cost savings for operators. Therefore, including these additional assessment methods in the proposed rule would not impose an additional cost burden on pipeline operators.

With regard to conducting integrity assessments using ILI, internal corrosion direct assessment (ICDA), or SCCDA, the proposed rule would invoke certain consensus industry standards by reference. When the IM rule was promulgated, industry standards for these assessment methods were still under development. Minimal guidance was provided in ASME B31.8S, incorporated by reference into regulations, but the current rule and ASME B31.8S are generally silent on specific guidance for successfully performing such assessments. Subsequently, NACE International, ASME, and the American Society for Nondestructive Testing (ASNT) have developed consensus industry standards for these assessment methods. These standards have been used successfully since the mid-2000s, and are the best available guidance. Most operators already successfully utilize these standards when conducting these types of assessments. Therefore, incremental cost to operators from incorporating these standards by reference in the pipeline safety regulations would be negligible compared to the cost of the additional scope described in Section 3.2.

The proposed rule expands the performance-based language to clarify that operators must assure that persons qualified by knowledge, training, and experience must analyze the data obtained from an ILI to determine if a condition could adversely affect the safe operation of the pipeline. Operators must also explicitly consider uncertainties in reported results in identifying and characterizing anomalies. This includes, but is not limited to: tool tolerance, detection threshold and probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties, and verifying actual tool performance. Such issues are generally addressed in the ASME standard, either explicitly or implicitly. These requirements are incorporated in §192.921(a) by reference to ASME B31.8S, Section 6.2 as if they were set out in full (see §192.7(a)). Since these are not new requirements, the language change does not impose an additional cost burden on pipeline operators.

<u>Repair Criteria</u>
49 CFR § 192.933(a) specifies the overarching requirement to promptly remediate conditions that could reduce a pipeline's integrity. Section 192.933(c) specifies the timeframe for performing remediation, unless a condition meets one of the special requirements specified in §192.933(d). Each of the proposed additions to § 192.933(d) is discussed below.

Immediate Condition: Metal Loss Defects that Exceed 80% of Wall Thickness. Currently, 49 CFR §192.933(d)(1)(i) requires that a calculation of the remaining strength of the pipe that shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly be treated as an immediate condition. Suitable remaining strength calculation methods include ASME/ANSI B31G, RSTRENG, or an alternative equivalent method. These are incorporated by reference in § 192.7(c) but are only valid for metal loss defects with depths less than 80% of pipe wall thickness. The existing rule implicitly treats defects of greater than or equal to 80% defect depth as immediate conditions, as clarified in Frequently Asked Question (FAQ)-241.[27] PHMSA is proposing to explicitly list this immediate condition in §192.933(d)(1). Inclusion would not represent a new or different requirement than the existing regulation, and thus would not impose an additional cost.

Immediate Condition: Significant Stress Corrosion Cracking. Section 192.933(d)(1) requires that stress corrosion cracking be treated as an immediate condition through reference to ASME B31.8S, Section 7 (see §192.7(a)). The proposed rule defines and explicitly list significant stress corrosion cracking in §192.933(d)(1); however, by limiting the immediate condition to *significant* stress corrosion cracking (instead of *all indications* of stress corrosion cracking), this revision would represent a relaxation of the existing requirement. PHMSA proposes to treat other cracks or crack-like indications (which would include stress corrosion cracking that would not meet the definition of significant) as one-year conditions in §192.933(d)(2). Therefore, these additional specific remediation requirements would not impose an additional cost burden on pipeline operators.

Immediate Condition: Metal-Loss Affecting a Detected Longitudinal Seam, and Significant Selective Seam Corrosion. Section 192.933(d)(1) requires that metal-loss affecting a detected longitudinal seam be treated as an immediate condition through reference to ASME B31.8S, Section 7 (see §192.7(a)). PHMSA is proposing to add the following immediate conditions: an indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency, or high frequency electric resistance welding or by electric flash welding, and any indication of significant selective seam corrosion selective seam corrosion. Selective seam corrosion is a special case of metal-loss affecting a longitudinal seam, in which the corrosion occurs along the seam and becomes a groove, or crack-like defect. Pipe seams formed by direct current, low-frequency or high-frequency electric resistance welding, or by electric flash welding are particularly vulnerable to failure due to selective seam corrosion because of the higher likelihood of poor bond-line fusion characteristic of these manufacturing processes.

PHMSA is proposing to explicitly list these conditions in §192.933(d)(1); however, by limiting the immediate condition to significant selective seam corrosion (instead of all indications of selective seam corrosion), this revision represents a relaxation of the existing requirement, which requires an immediate response for all indications of selective seam

[27] FAQ-241. May I exclude metal loss indications of >80% wall loss from immediate repair requirements per 933(d)(1), if B31G or RSTRENG predict a failure pressure of greater than 1.1 times MAOP? [08/02/2006]
No. B31G and RSTRENG are not valid for situations with metal loss exceeding 80 percent of wall thickness (see Figure 1-2 in B31G, which requires "repair or replace" for conditions involving wall loss greater than 80 percent). These methods cannot be used to determine failure pressure for these situations.
The Gas Integrity Management FAQs are available online: http://primis.phmsa.dot.gov/gasimp/faqs.htm#top37

corrosion. PHMSA proposes to treat other cracks or crack-like indications (which would include selective seam corrosion that would not meet the definition of significant) as one-year conditions in §192.933(d)(2). Therefore, these additional specific remediation requirements do not impose an additional cost burden on pipeline operators.

Additional One-Year Conditions: Metal-loss and Cracks or Crack-like Defects Other than Immediate Conditions. Currently, 49 CFR §192.933(d)(2) does not explicitly list a number of conditions that are explicit in the corresponding hazardous liquid integrity management rule as scheduled conditions (refer to §195.452(h)).

The proposed rule would impose additional costs compared to existing requirements for remediation of these four proposed metal-loss one-year repair criteria, because it would require a more prompt response. The size of defects are covered under the current rule, such that repair would eventually be required in most cases.[28] However, the proposed mandatory deadline would necessitate a more timely response by operators. The cost of these proposed one-year repair criteria is evaluated in Sections 3.2.2 through 3.2.4.

Preventive and Mitigative Measures

49 CFR § 192.935 requires that operators identify additional preventive and mitigative (P&M) measures to protect High Consequence Areas. Operators must base the additional measures on specific risk assessments. The existing rule does not prescribe what those additional measures must be, however it does list examples of measures operators could take. The proposed rule would expand the listing of example P&M measures. Examples serve to promote awareness of the range of actions an operator could consider, but do not constitute new or different requirements.

The proposed rule would also require that seismicity be analyzed to mitigate the threat of outside force damage. Addressing seismicity is already required § 2.2(c)(3)(d) as part of addressing outside force threat, through incorporation by reference of ASME B31.8S (see § 192.917(a)). Explicit language is proposed to address Section 29 of the Act which requires operators to consider the seismicity of the geographic area in identifying and evaluating all potential threats to each pipeline segment, pursuant to 49 CFR 192 and 49 CFR 195. However, this does not constitute a new or differing requirement from the current rule.

Lastly, the proposed rule would add specific enhanced measures for managing external and internal corrosion on pipelines inside HCAs. This aspect of the proposed rule is analyzed in Topic Area 5, Corrosion Control.

Therefore, with the exception noted, the proposed changes to the P&M program element requirement would not impose an additional cost burden on pipeline operators.

Periodic Evaluations and Assessments

49 CFR § 192.937 requires operators to periodically assess and evaluate the integrity of covered HCA segments. PHMSA determined that conforming amendments would be needed to implement, and be consistent with, the proposed rule changes for: data integration, risk assessment, threat identification, and risk assessment (§ 192.917); baseline assessment methods (§ 192.921); decisions about remediation (§ 192.933); and

[28] In some cases, the repair timeframe might extend beyond the next assessment deadline, and might not be repaired before the subsequent assessment, in which case the anomaly would be reevaluated

identification of additional P&M measures (§ 192.935). For the reasons described in Sections 3.2.1.1 through 3.2.1.5, these conforming changes do not constitute new or differing requirements. Therefore, this requirement does not impose an additional cost burden on pipeline operators.

49 CFR § 192.941 and Appendix E, among other requirements, specify that to address the threat of external corrosion on cathodically protected pipe in a HCA segment, an operator must perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years. PHMSA proposes to make conforming edits to the language of this requirement to accommodate the revised definition of the term “electrical survey”, which would be replaced with “indirect inspection” to accommodate other techniques in addition to close-interval surveys. This clarification does not change the intent of the requirement. Therefore, this clarification does not impose an additional cost burden on pipeline operators.

Reassessment Interval

Section 5 of the Act identifies a technical correction amending Title 49 of the U.S. Code to allow the Secretary of Transportation to extend the 7-year IM reassessment interval for an additional six months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension. The proposed rule codifies this statutory requirement. Even though the notification requirement might require a negligible expenditure on the part of pipeline operators, it would be more than offset by the savings associated with having increased operational flexibility to schedule assessments beyond the mandatory seven-year deadline. Therefore, this requirement does not impose an additional cost burden on pipeline operators.

3.2.3 ANALYSIS ASSUMPTIONS

Because gas operators have not (prior to 2010) been required to report on the type of integrity repair conditions being evaluated, PHMSA assumed that the experience of hazardous liquid operators can be applied to this analysis.

3.2.4 ESTIMATION OF COSTS

This analysis is structured as follows:

1. Estimate the number of conditions to which this requirement would apply
2. Estimate the average length of time an operator has to remediate the condition under current regulation
3. Estimate the present unit cost of repair
4. Estimate the total cost of repair
5. Calculate the difference in present value of the cost of repair within one year compared to the longer average timeframe

3.2.4.1 Number of Conditions

The proposed rule will require operators to accelerate repairs on certain 180 day repair conditions. PHMSA estimated the expected number of 180 day gas transmission defects detected a year based on HCA miles and assessment and repair condition discovery data submitted in gas transmission and hazardous liquid annual reports (Table C-2).

Under current regulations HCA segments must be re-assessed every seven years. Therefore the average annual mileage is assessed is one seventh of total HCA mileage. Given potential overlap with Topic Area 1 HCA miles subject to MAOP verification tests, PHMSA did not include these miles. PHMSA therefore considered 2,407 miles of HCA lines (**Table 3-60**).

Table 3-60. Calculation of HCA Mileage, Topic Area 2

Scope	Miles
HCA[1]	19,872
HCA MAOP verification testing under Topic Area 1[2]	3,024
HCA less Topic Area 1 mileage	16,849
Average assessed per year[3]	2,407

1. Source: PHMSA Annual Reports
2. See section 3.1.
3. HCA miles less topic Area 1 divided by 7 years.

PHMSA then estimated the number of 180-day conditions which could occur on the regulated segments. Gas transmission operators do not currently report 180-day conditions separate from other scheduled repairs. As the new repair criteria are similar to those for hazardous liquid pipeline, PHMSA assumed that a similar proportion of gas transmission scheduled conditions would be classified as 180-day conditions. PHMSA estimated that approximately 81% of scheduled repair conditions will be 180-day conditions (**Table 3-61**).

Table 3-61. Hazardous Liquid Scheduled Repair Conditions, 2004-2009

Repair Condition	Number	Percent of Total
60-day conditions	4,673	19%
180-day conditions	20,468	81%
Total	25,141	100%

Source: 2004-2009 Hazardous Liquid Annual Reports; see Table C-2

Based on the information detailed above and the historical scheduled repair condition defect discovery rate on gas transmission lines (0.107 / mile, see Table C-2), PHMSA estimated that operators will discover approximately 210 180-day repair conditions per year (**Table 3-62**).

Table 3-62. Estimation of 180-Day Repair Conditions

Component	Value
HCA miles assessed per year	2,407
Scheduled repair conditions per mile assessed[1]	0.107
Expected scheduled repair conditions per year	258
180 conditions (% of scheduled conditions)	81%
Expected 180-day conditions per year	210

1. 2004-2009 Gas Transmission scheduled repair rate, see Table C-2.

3.2.4.2 Average Repair Time

Under the existing rule, remediation of these conditions could be deferred for up to 10 years

or more, as described in Section 3.2.1. PHMSA does not collect data for how long an operator takes to actually complete the repair of scheduled anomalies. Because the gas IM rule requires a reassessment every seven years, conditions with a remediation schedule greater than seven years would likely be reassessed and the repair schedule adjusted based on updated assessment data. PHMSA assumed a repair schedule of 5 years as a representative average. The cost associated with the proposed requirement is then the difference between the cost of a repair performed the same year as a condition is discovered and the present value of the same repair completed in 5 years (i.e., the repair is accelerated by 4 years).

3.2.4.3 Unit Cost of Repair

The cost of repair depends in large part on the size of the pipe, the size of areas to be repaired, the type of repair, and location (geographic region). A range for the typical cost of repair activities is shown in **Table 3-63**.

Table 3-63. Range of Typical Repair Costs

Repair Method (Length)	West (Except West Coast), Central, Southwest[1]	South, West Coast	East[2]
12-inch Diameter			
Composite Wrap (5’)	$9,600	$12,000	$13,800
Sleeve (5’)	$12,800	$16,000	$18,400
Pipe Replacement (5’)	$41,600	$52,000	$59,800
Material Verification (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$16,000	$20,000	$23,000
Sleeve (20’)	$19,200	$24,000	$27,600
Pipe Replacement (20’)	$51,200	$64,000	$73,600
Material Verification[1] (20’)	$4,000	$4,000	$4,000
24-inch Diameter			
Composite Wrap (5’)	$14,400	$18,000	$20,700
Sleeve (5’)	$19,200	$24,000	$27,600
Pipe Replacement (5’)	$62,400	$78,000	$89,700
Material Verification[1] (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$24,000	$30,000	$34,500
Sleeve (20’)	$28,800	$36,000	$41,400
Pipe Replacement (20’)	$76,800	$96,000	$110,400
Material Verification[1] (20’)	$4,000	$4,000	$4,000
36-inch diameter			
Composite Wrap (5’)	$21,600	$27,000	$31,050
Sleeve (5’)	$28,800	$36,000	$41,400
Pipe Replacement (5’)	$93,600	$117,000	$134,550
Material Verification[1] (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$36,000	$45,000	$51,750
Sleeve (20’)	$43,200	$54,000	$62,100
Pipe Replacement (20’)	$115,200	$144,000	$165,600

Table 3-63. Range of Typical Repair Costs			
Repair Method (Length)	**West (Except West Coast), Central, Southwest[1]**	**South, West Coast**	**East[2]**
Material Verification[1] (20')	$4,000	$4,000	$4,000
Source: PHMSA best professional judgment 1. 80% of South/West Coast. 2. 115% of South, West Coast.			

3.2.4.4 Estimated Total Cost of Repair

Most anomalies are repaired using composite wraps or steel sleeves. Relatively few anomalies are repaired by pipe replacement. PHMSA used BPJ to estimate that

- 30% of anomalies are repaired by composite wrap
- 60% are repaired by sleeve
- 10% are repaired by pipe replacement.

Since there is variation in repair costs based on geographic locale, PHMSA distributed the estimated number of repairs to each region of the country based on the ratio of onshore gas transmission pipeline in each region:

- Eastern – 10%
- Southern and West Coast – 15%
- Southwest, Central, and West (excluding West Coast states) – 75%.

PHMSA equally distributed the numbers of repairs among the six pipe diameter/repair size combinations shown in Table 3-63. Using the above assumptions, repair costs, and estimated number of repairs, PHMSA calculated the total annual cost of performing the repairs to be approximately $14.1 million.

3.2.4.5 Cost of Accelerating Repair Timeframes

PHMSA compared the estimated annual cost of performing the one-year repairs with the present value of those same repairs if done five years in the future; in other words, four years sooner. **Table 3-64** shows the difference and represents the estimated annual cost of the proposed requirement to establish more prompt and explicit timeframes for completing metal loss repairs. **Table 3-65** shows the total and average annual present value over the study period.

Table 3-64. Present Value of Estimated Annual Cost of More Timely Repair of Non-Immediate Conditions (Millions)		
Estimate	**7% Discount Rate**	**3% Discount Rate**
Cost of repairs	$14.1	$14.1
Cost of repairs delayed 4 years	$10.8	$12.6
Difference (estimated cost of proposed rule)	$3.4	$1.6

Table 3-65. Present Value Costs, Topic Area 2 (Millions)[1]	
7% Discount Rate	**3% Discount Rate**

Total	Average Annual	Total	Average Annual
$32.7	$2.2	$19.4	$1.3
1. Total is of the 15 year compliance period; average annual is total divided by 15.			

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3.3 MANAGEMENT OF CHANGE PROCESS IMPROVEMENT

Topic Area 3 includes the following changes:

1. Evaluate and mitigate risks during Management of Change (MoC)
2. Develop MoC process beyond IMP- and Control Center-related processes

3.3.1 PROBLEM STATEMENT

Section 49 CFR § 192.13 prescribes general requirements for onshore gas transmission pipelines. The proposed rule would add a new paragraph, § 192.13(d), to establish a general clause for operators to evaluate and mitigate risks, as necessary, during all phases of the useful life of a pipeline, including managing changes to pipeline design, construction, operation, maintenance, and integrity, and to articulate specific requirements for a MoC process for onshore gas transmission pipelines.

3.3.2 ASSESSMENT OF REGULATORY IMPACT

New mandatory MoC requirements would apply to all onshore gas transmission pipelines under the proposed rule. However, similar MoC requirements currently apply to pipeline segments in HCAs and control centers, and those operators have formal processes in place to address changes that occur in those areas. Pipeline operators currently apply MoC principles to all of their pipeline systems with varying degrees of process formality. Thus, the incremental impact to operators is limited in scope.

3.3.3 ANALYSIS ASSUMPTIONS

Based on its experience and BPJ, PHMSA made the following key assumptions in estimating the costs of the proposed changes:

- Approximately 20% of the operators that do not have IM programs would have to develop processes to more formally implement the new MoC rule requirements
- A typical pipeline system has eight compressor stations and three piping sections.
- A typical pipeline system would have one compressor station change event and three piping section change events per year.

3.3.4 ESTIMATION OF COSTS

The steps for estimating costs are:

1. Estimate the number of operators that do not have IM programs.
2. Estimate the number of these operators that would have to develop MoC processes.
3. Estimate the unit costs of developing and implementing MoC processes.
4. Estimate total incremental annual compliance costs.

3.3.4.1 Estimation of Incrementally Affected Operators

Based on PHMSA gas transmission operator annual report data, there are approximately 350 onshore gas transmission system operators that do not have IM programs (do not operate HCA pipeline mileage). These operators implement MoC practices but in a less formal manner than would be required by the proposed new rule. Based on BPJ, PHMSA assumed that approximately 20% (approximately 70) of these operators would have to develop processes to more formally implement the new MoC rule requirements. Some of these operators would need to review and revise existing procedures; others would need to establish new processes.

3.3.4.2 Estimation of Unit Costs

The unit costs of the new MoC procedures for affected operators will consist of the one-time costs associated with developing or designing the new procedures and the annual/recurring costs of applying those procedures to any covered event. For both the one-time and annual costs, PHMSA used BPJ to estimate the activities, labor hours, and staff associated with creating and implementing MoC processes for: 1) cases in which nominally formal processes exist (low cost) and 2) cases where only minimal processes exist (high cost). To estimate overall unit costs, PHMSA used the average of the low and high cost estimates.

Table 3-66 shows the labor rates applied in the cost calculations. **Table 3-67** presents one-time unit costs for initial development of the new procedures; it includes a breakdown by activity and associated level of effort for both the low and high cost. **Table 3-68** provides the estimates for unit costs on a per event basis.

Table 3-66. Labor Rates

Occupation Code	Occupation	Industry	Labor Category	Mean Hourly Wage	Total Labor Cost[2]
17-2141	Mechanical Engineers	Oil and Gas Extraction	Senior engineer	$74	$99
11-3071	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55

Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).
2. Mean hourly wage plus mean benefits ($25.01 per hour worked).

Table 3-67. Onetime Cost of Management of Change Process Development[1]

Activity	Low Estimate		High Estimate	
	Hours	Cost[2]	Hours	Cost[2]
Review existing MoC procedures for IMP- and Control Center-related changes	3	$297	0	$0

Table 3-67. Onetime Cost of Management of Change Process Development[1]				
Activity	Low Estimate		High Estimate	
	Hours	Cost[2]	Hours	Cost[2]
Revise and expand scope of procedures	16	$1,584	0	$0
Establish procedures	0	$0	80	$7,922
Notify personnel and provide implementation guidance and instruction	4	$396	20	$1,980
Total	**23**	**$2,277**	**100**	**$9,902**
1. Source: PHMSA best professional judgment. Low estimate reflects nominally formal existing processes and high estimate reflects only minimal existing processes.				

Table 3-68. Per Event Cost of Implementing Management of Change Processes				
Activity	**Labor Category**	**Labor Cost[1] ($/hour)**	**Hours**	**Cost**
Maintenance/operating personnel or engineer identifies a change, invoking the process	Operator	$55	1	$55
Obtain approval to pursue change	Manager	$86	1	$86
Evaluate and document technical and operational implications of the change	Sr. Engineer	$99	12	$1,188
Obtain required work authorizations (e.g., hot work and lockout-tag out permits)	Project Engineer	$81	3	$243
Formally institutionalize change in official "as-built" drawings, facilities lists, data books, and procedure manuals	Project Engineer	$81	8	$648
Communicate change to all potentially affected parties	Manager	$86	2	$172
Train and qualify involved personnel	Operator	$55	20	$1,100
Total	**NA**	**NA**	**47**	**$3,492**
1. See Table 3-66.				

3.3.4.3 Estimation of Total Incremental Compliance Costs

To estimate total onetime costs, PHMSA used the average of the low and high onetime costs ($2,277 + $9,902) / 2 = $6,090) and multiplied by the total number of operators ($6,090 × 70 = $ $426,281). To calculate annual implementation costs, PHMSA assumed that operators would experience four MoC events per year, and multiplied the per event unit cost by the number of operators and number of events ($3,492 × 70 × 4 = $977,760). PHMSA assumed that operators would develop processes in the first year following finalization of the rule, and that implementation occurs annually. **Table 3-69** shows total annual compliance costs.

Table 3-69. Present Value Costs, Topic Area 3[1]				
Component	**Total (7%)**	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
Onetime process development	$426,195	$28,413	$426,195	$28,413
Annual implementation[1] ($977,760)	$9,528,729	$635,249	$12,022,608	$801,507

Table 3-69. Present Value Costs, Topic Area 3[1]				
Component	**Total (7%)**	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
Total	**$9,954,924**	**$663,662**	**$12,448,803**	**$829,920**

Note: Detail may not add to total due to rounding.
1. Total is present value over 15 year compliance period; average annual is total divided by 15.

3.4 CORROSION CONTROL

The proposed rule includes the following changes related to corrosion control:

1. Perform pipe coating assessment for steel onshore transmission pipe installed in ditch [49 CFR § 192.319]
2. Protective coating strength requirements [§ 192.461]. Requirements also provided as a preventive and mitigative (P&M) measure for covered segments [§ 192.935(g)]
3. Perform pipe coating assessment when there are indications of compromised integrity
4. One-year maximum for remedial action for external corrosion mitigation deficiencies [§ 192.465] and 6 months provided as a P&M measure for covered segments [§ 192.935(g)]
5. Close interval survey (CIS) required in accordance with 49 CFR Part 192 Appendix D [§ 192.465] and as a P&M measure for covered segments [§ 192.935(g)]. Appendix D also:
    a. Eliminates three criteria for acceptability in 49 CFR Part 192 Appendix D for steel, cast iron, and ductile iron structures
    b. Clarifies terminology [§ 192.3 and Appendix D]
    c. Alters acceptability criteria in Part 192 Appendix D for aluminum structures
    d. Updates interpretation of voltage measurement
6. Additional stray/interference current remedial action, including 6 months deadline for addressing [§ 192.473] and provided as a P&M measure for covered segments [§ 192.935(g)]
7. Develop and implement a gas stream monitoring program, including semi-annual reviews [§ 192.477] and provided as a P&M measure for covered segments [§ 192.935(f)]

3.4.1 PROBLEM STATEMENT

Corrosion continues to be a significant problem for gas transmission pipelines. The incident data reported by operators is shown in **Table 3-70**. Nineteen percent of reported gas transmission incidents from 2003 through 2015 were due to internal or external corrosion. Also, the annual numbers of corrosion-caused incidents occurring in that time period do not show a declining trend over time. Thus, additional requirements are needed to enhance and improve internal and external corrosion control programs required in 49 CFR Part 192, Subpart I.

Table 3-70. Reported Gas Transmission Incidents Due to Corrosion (Onshore and Offshore)

Year	Internal Corrosion	External Corrosion	Total Corrosion	Total All Causes
2003	11	11	22	93
2004	14	9	23	103
2005	7	12	19	160
2006	11	12	23	130
2007	18	17	35	110
2008	8	11	19	122
2009	10	9	19	105
2010	19	10	29	105
2011	14	4	18	114
2012	14	13	27	102
2013	13	5	18	103
2014	9	9	18	129
2015	13	8	21	129
Total	**161**	**130**	**291**	**1505**

Source: PHMSA Incident Reports

Pipe Installation
49 CFR § 192.319 currently prescribes requirements for installing pipe in a ditch, including requirements to protect pipe coating from damage during the process. However, during handling, lowering, and backfilling, pipe coating can be damaged and its ability to protect against external corrosion compromised. An example of the consequences of such damage was the 2011 rupture of TransCanada's Bison Pipeline, near Gillette, Wyoming. The probable cause of the incident was undetected coating and mechanical damage during construction, which subsequently led to pipeline failure. To help prevent recurrence of such incidents, PHMSA has determined that additional requirements are needed to verify that pipeline-coating systems for protection against external corrosion are not damaged during the installation and backfill process.

External Corrosion Coatings
49 CFR § 192.461 currently prescribes requirements for protective coating systems. However, certain types of coating systems that have been used extensively in the pipeline industry can shield the pipe from cathodic protection if the coating disbonds from the pipe. The NTSB determined this was a significant contributing factor in the major crude oil spill that occurred on an Enbridge pipeline near Marshall, Michigan in 2010. PHMSA has determined that additional requirements are needed to specify that coating should be non-shielding to cathodic protection and to verify that pipeline coating systems for protection against external corrosion have not become compromised and have not been damaged during the installation and backfill process.

External Corrosion Monitoring
Existing rules in 49 CFR § 192.465 require operators to monitor cathodic protection. However, the rule does not specify the timeframe in which remedial actions are required to correct deficiencies - only that remedial actions must be promptly taken. Also, the rule does not define "prompt." To address this gap, the proposed rule would amend § 192.465 to require, except for distribution lines, close-interval surveys if annual test station readings indicate cathodic protection is below the level of protection required in 49 CFR Part 192, Subpart I. The proposed rule would further define "prompt remediation" to restore adequate corrosion control as meaning within one year of identifying the deficiency.

Update for Cathodic Protection
Appendix D to 49 CFR Part 192 specifies requirements for cathodic protection of steel, cast iron & ductile pipelines. PHMSA has determined that this guidance needs to be updated to incorporate lessons learned since Appendix D was first promulgated in 1971. Accordingly, the proposed rule would update Appendix D by eliminating outdated guidance on cathodic protection and interpretation of voltage measurement to better align with current standards and industry practice.

Interference Current Surveys
Interference currents can negate the effectiveness of cathodic protection systems. 49 CFR § 192.473 prescribes general requirements to minimize the detrimental effects of interference currents. However, specific requirements to monitor and mitigate detrimental interference currents have not been prescribed in 49 CFR Part 192, Subpart I. In 2003, PHMSA issued Advisory Bulletin ADB-03-06 (68 FR 64189). The bulletin advised each operator of a natural gas transmission or hazardous liquid pipeline to determine whether new steel pipelines are susceptible to detrimental effects from stray electrical currents. Based on this evaluation, an operator should carefully monitor and take action to mitigate such detrimental effects. Since the Advisory Bulletin, PHMSA continues to identify cases where significant pipeline defects are attributed to corrosion caused by interference currents. Examples include CenterPoint Energy's CP line (2007), Keystone Pipeline (2012), and Overland Pass Pipeline (2012). Therefore, PHMSA has determined additional requirements are needed to explicitly require that operators conduct interference surveys and remediate adverse conditions in a timely manner. The proposed rule would amend § 192.473 to require that an operator's program include interference surveys to detect the presence of interference currents and to take remedial actions within 6 months of completing the survey.

Internal Corrosion Monitoring
49 CFR § 192.477 prescribes requirements to monitor internal corrosion by coupons or other means if corrosive gas is being transported. However, the existing rules do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system changes, changing gas supply, upset conditions, or other changes. This could result in pipelines that are not monitored for internal corrosion because an initial assessment did not identify the presence of corrosive gas. In September 2000, following the explosion of a natural gas pipeline in Carlsbad, NM, PHMSA issued Advisory Bulletin ADB-00-02, dated September 1, 2000 (65 FR 53803). The Advisory Bulletin advised owners and operators of natural gas transmission pipelines to review their internal corrosion monitoring programs and consider factors that influence the formation of internal

corrosion, including gas quality and operating parameters. Pipeline operators continue to report incidents attributed to internal corrosion. Between 2003 and 2015, operators reported 161 incidents attributed to internal corrosion, suggesting the existence of gaps in existing market-based gas quality monitoring practices.

Thus, PHMSA has determined that additional requirements are needed to assure that operators effectively monitor gas stream quality to identify if and when corrosive gas is being transported and to mitigate deleterious gas stream constituents (e.g., contaminants or liquids).

3.4.2 ASSESSMENT OF REGULATORY IMPACT

This section describes the incremental impact of each of these changes.

Pipe Installation

The proposed rule adds a new paragraph 49 CFR § 192.319(c) that would require that all newly installed transmission pipe undergo a physical coating assessment using either alternating current voltage gradient (ACVG) or direct current voltage gradient (DCVG) to locate coating flaws.[29] The proposed rule further requires that moderate or severe coating damages be remediated by recoating. The rationale behind this change is that most operators perform the required high voltage holiday detection (called "jeeping") on the pipeline prior to it being set into the ditch; however, coating damage can occur after the pipe is lowered into the ditch and the ditch backfilled. Many of the high resistance coatings are brittle and any impact with a rock or the ditch wall can cause coating damage, and over time, if the cathodic protection electrical potential is not sufficient or if there are interference currents, external corrosion can occur. Besides damage to fusion bonded epoxy coatings, field wrapped joints are also prone to construction damage. Testing the newly installed pipeline after backfilling is an excellent way of finding potential flaws in the coating that occur during installation of the pipe in the ditch and that could, over time, enable external corrosion to affect pipeline integrity.

The proposed rule would require that operators perform a coating survey after initial backfill to identify coating damage that might have occurred during the backfill process. However, since this is for new pipelines only, it does not apply to existing pipelines. Therefore, there is no current cost impact on existing pipelines or pipeline operators. (Note: a similar requirement would be added to § 192.461(f) for repairs and pipe replacements performed for existing pipeline facilities.) This would be a negligible cost factor for a new pipeline project.

External Corrosion Coatings

Currently, § 192.461(a)(4) prescribes that coatings have sufficient strength to resist damage due to handling and soil stress. This paragraph would be revised in the proposed rule to clarify and expand on the types of activities covered by the general term "handling." It would specify that coatings selected have sufficient strength to adequately withstand handling throughout the entire installation process after being applied to the pipe (transportation, field handling, installation, boring, backfilling, and soil stresses). For example, this requirement would provide greater assurance that operators specify the correct

[29] Old paragraph § 192.319(c) would become paragraph § 192.319(d).

coating for the intended application (e.g., avoid pipe coatings designed for direct burial when the pipe is installed by boring methods). This requirement comports with current industry standards that have evolved in recent years to address this aspect of pipeline construction.

A new paragraph, § 192.461(f), would require a coating survey using either ACVG or DCVG whenever a repair is made that results in more than 200' of backfill or if other assessment methods show the possibility of coating issues in the area of the repair. If an operator finds either moderate or severe coating damage via the survey, then prompt remedial action would be required to mitigate the situation. Coating survey costs range from $2,000 to $50,000 per mile depending on several factors: the environment, traffic control, and the amount of miles being surveyed. The cost of repairs could add significantly more cost per mile, but over the long term these repairs would result in an improvement in pipeline integrity and a reduction in cathodic protection (CP) currents needed to protect the pipeline (and thus lengthening the life of the CP anodes).

Currently, post-backfill coating surveys are not normally being done and many locations may be left with areas that are subject to future external corrosion due to coating flaws. Often, operators find that if one area has corrosion or coating damage there are adjacent locations with similar problems. Performing testing and excavations when crews are already mobilized is significantly less expensive than having them return to an adjacent area some time later.

<u>External Corrosion Monitoring</u>

The existing rule 49 CFR § 192.465 specifies that operators take "prompt" corrective action. The proposed rule would provide more explicit standards for timeliness of corrective action by specifying that remedial action must be completed promptly, but no later than the next monitoring interval specified in § 192.465 or one year after deficiencies are discovered if no monitoring interval applies. This is consistent with PHMSA current guidance to operators. Therefore, this would have minimal regulatory impact.

In addition, the proposed rule for HCAs, § 192.935(g)(3)(i), would require remedial action within six months of the identification of a deficiency rather than one year.

A new paragraph, § 192.465(f), would require that operators perform a close interval survey (CIS) when they have a test station reading of low cathodic protection (per revised 49 CFR Part 192 Appendix D). The CIS is to be performed in both directions from the test station to the adjacent test stations. Where the CIS finds low cathodic protection exists, additional remediation must be taken, which could include doing a direct examination to determine the condition of the coating. An alternative to the direct examination may be the use of indirect inspection techniques.

PHMSA has noted that many operators have only taken readings at test stations, and when they fall below the minimum requirements of 49 CFR Part 192 Appendix D, the operators add additional voltage to rectifiers or install additional anodes without assessing the causes of the low readings. In some situations operators have increased the voltage too high, so that test stations that previously had good readings elsewhere ended up with too much CP voltage, which could be detrimental to the coatings in those locations. This type of remediation does not permanently solve the problem and may cause other issues such as

coating failures. A CIS is needed to properly characterize a CP problem, determine its location, and understand the cause of the substandard reading at the test station.

In addition to the proposed new requirements for § 192.465(f), § 192.935(g)(2)(iv)(B) would require pipe-to-soil test stations be located at half-mile intervals within each HCA segment and at least one station be within each HCA, if practicable.

Cathodic Protection

49 CFR Part 192 Appendix D contains technical guidance for CP, but has not been updated since it was first promulgated in 1971. The proposed rule would update Appendix D to reflect current industry practices and technology, but would have no regulatory impact in terms of compliance. Proposed changes include for steel, iron and ductile iron structures, three of the five existing criteria (which are seldom used) would be eliminated. The remaining two criteria, which include a negative 0.85 VDC, taking voltage drop (loss of voltage due to soil resistance) into account with a saturated copper-copper sulfate half-cell, and a negative 100 millivolt polarization shift, are the main methods operators have been using to confirm adequate cathodic protection.

Some wording changes are proposed to better define how to interpret IR drop, but the technical intent is unchanged.

Some wording changes are proposed to better define what is required and for consistency with terminology used in 49 CFR Part 192 Subpart I.

Interference Current Surveys

A proposed change to 49 CFR Part 192 § 192.473(c) would require that for pipelines subject to stray currents, operators take action via a plan to minimize the detrimental effects of those currents. Further, the proposed change would add specificity to the requirements of the plan. It would require the operator to perform interference surveys, analyze the data from the surveys, and implement remedial action within six months. The sources of stray current problems are commonplace; they can result from other underground facilities, such as the CP systems from crossing or parallel pipelines, light rail systems, commuter train systems, high-voltage AC electrical lines, or other sources of electrical energy in proximity to the pipeline. If stray current or interference issues are not remediated, accelerated corrosion could occur and potentially result in a leak or rupture.

In addition the proposed new 49 CFR Part 192 § 192.935(g)(1) would require (i) periodic interference surveys whenever needed, but not to exceed every 7 years; (ii) remediation of AC interference that is greater than 50 amperes per meter squared; and (iii) documented justification if AC interference between 20 and 50 amperes per meter squared is not remediated.

Internal Corrosion Monitoring

The existing rule in 49 CFR § 192.477 requires operators to monitor internal corrosion if corrosive gas is being transported. However, the rule is silent on standards for determining if corrosive gas is being transported or if changes occur that could introduce corrosive contaminants in the gas stream. The proposed rule would require operators to develop and implement gas stream monitoring programs to measure gas stream components that could cause internal corrosion. At a minimum, quarterly testing would be required along with

quarterly checks on the effectiveness of the mitigation strategy. In addition, the operator would be required to review its program every six months.

In § 192.935(f) the proposed rule would require the use of specific gas quality monitoring equipment for HCA segments, including but not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and hydrogen sulfide sampling. The maximum amounts of contaminants that would require operator action are specified for carbon dioxide, moisture content, and hydrogen sulfide.

3.4.3 ANALYSIS ASSUMPTIONS

PHMSA estimated coating survey costs assuming an average backfill length of 500 feet. PHMSA estimated costs for close interval surveys assuming that annual test station readings for 0.5% of transmission mileage are out of specification. In addition, although not universally deployed, some operators already perform close interval surveys as a matter of good engineering practice. In these cases, operators would already be in compliance with the proposed rule. PHMSA assumed that operators are performing close interval surveys in 15% of Class 1 mileage; 10% of Class 2; 5% of Class 3; and 5% of Class 4 mileage.

In HCAs, PHMSA assumed that an additional test station would be added for each HCA mile to meet the proposed requirement to have test stations every half mile.

The proposed rule would require interference surveys be conducted in situations where the pipeline is subject to stray currents. Most pipeline segments would not be subject to this requirement. Pipeline segments subject to this requirement would be those segments in close proximity to other underground facilities, such as CP systems from crossing or parallel pipelines, light rail systems, commuter train systems, high voltage AC electrical lines, or other sources of electrical energy in proximity to the pipeline. For purposes of this analysis, PHMSA assumed that 1% of Class 1 and 2 pipelines and 3% of Class 3 and 4 pipelines would be subject to this requirement. PHMSA assumed Class 1 and 2 are mainly AC interference and Class 3 and 4 are mainly DC interference.

In addition, although not universally deployed, many operators already perform such interference surveys as a matter of good engineering practice. This is most often the case in urban/suburban areas where electrical interference is a more common occurrence. In these cases, operators would already be in compliance with the proposed rule. PHMSA assumed that operators are performing electrical interference surveys as needed in 10% of Class 1 – 10% mileage; 10% of Class 2; 70% of Class 3; and 90% of Class 4 mileage.

Gas purchase, sales, and transport contracts generally include quality standards, and pipeline operators will usually have some mechanism to monitor contract compliance. PHMSA assumed that most of the inputs to the transmission system from gathering and production areas are already monitored. Thus, PHMSA assumes 95% existing compliance for Class 1 and 80% for Class 2. For Class 3 and 4, PHMSA assumed 100% compliance because all such lines are either local distribution companies (LDCs) are operating these lines and use the monthly or quarterly data from their suppliers or have their own equipment at their gate stations. PHMSA assumed other Class 3 and 4 operators have their gas analyzed upstream by, inter alia, interstate transmission companies.

3.4.4 ESTIMATION OF COSTS

This section describes the estimation of costs for each component. The general steps for

each are: estimate incremental effect in terms of number of surveys needed or mileage affected; estimate unit costs; multiply to obtain total incremental costs.

3.4.4.1 External Corrosion Coatings

The proposed rule would require coating surveys when an operator does a repair with an excavation of 200 feet or more. PHMSA used BPJ to estimate the costs for performing such surveys as shown in **Table 3-71**.

Table 3-71. Estimation of Coating Survey Costs

Class	Coating Survey Cost[1]	Number of Surveys	Cost[1]
1	$200	100	$20,000
2	$400	70	$28,000
3	$3,000	50	$150,000
4	$5,000	20	$100,000
Total	**NA**	**240**	**$298,000**

Source: PHMSA Best Professional Judgment.
1. Based on average survey length of 500 feet. Actual costs will vary depending on environment, traffic control, and survey length.

3.4.4.2 External Corrosion Monitoring

The cost of doing a close interval survey depends on the type of environment (similar to the coating survey), with the lowest cost in a Class 1 area with no traffic issues and the pipeline right of way is soil and the highest cost in a Class 4 area with the pipeline installed under pavement which must be drilled to get soil contact, and traffic restrictions are enforced and traffic plans are required (i.e. flag people, safety vehicles, etc.). PHMSA used BPJ to estimates the unit cost, mileage, current compliance, and mileage for which test station readings are out of specification (**Table 3-72**).

Table 3-72. Gas Transmission Close Interval Survey

Class	Close Interval Survey Cost ($/Mile)[1]	Mileage[2]	Current Compliance[1]	Out of Specification Test Station Readings (Annual)[1,3]	Total Costs[4]
1	$2,000	232,635	15%	0.5%	$1,977,398
2	$3,000	30,631	10%	0.5%	$413,517
3	$25,000	33,652	5%	0.5%	$3,996,120
4	$50,000	908	5%	0.5%	$215,683
Total	**NA**	**297,826**	**NA**	**NA**	**$6,602,718**

1. Source: PHMSA best professional judgment
2. Source: PHMSA 2014 Annual Report via PDM
3. Reflects long-standing requirements for operators to have CP systems and check test stations annually, and PHMSA inspection experience.
4. Calculated as the product of mileage, unit cost, out of spec rate, and (1-compliance rate).

In addition, the proposed revisions require that pipe-to-soil test stations be located at half-mile intervals within each HCA segment, and that at least one station be located within each HCA, if practicable. PHMSA used BPJ to estimate the incremental cost of this requirement as shown in **Table 3-73.**

Table 3-73. Cost to Add Test Station in HCA

HCA	Stations Required	Baseline	New Stations	Cost per Test	Total Cost

Miles[1]	per Mile	Compliance[2]	Required	Station[2]	
19,872	2	80%	7,949	$500	$3,974,492

HCA = high consequence area
1. Source: PHMSA annual reports.
2. Source: PHMSA BPJ
3. Unit cost represents approximately $400 in labor (2 workers for half day) and $100 in materials.

3.4.4.3 Interference Current Surveys

Since interference currents can be either AC or DC, the cost to perform interference current surveys depends not only on the environment but also the type of interference. PHMSA used BPJ to estimate the cost of this requirement, as shown in **Table 3-74**. For simplicity, PHMSA assumed a seven-year survey interval consistent with the requirement in § 192.935(g)(1) applicable to HCAs.

Table 3-74. Estimation of Costs for Interference Surveys

Class	Interference Survey Cost[1] ($/mile)	Total Mileage[2]	Current Compliance[1]	Incremental Need for Surveys[1]	Compliance Mileage[3]	Total Costs[4] ($/7 years)
1	4,000	232,635	10%	1%	2,129	$8,374,864
2	5,000	30,631	10%	1%	276	$1,378,389
3	10,000	33,652	70%	3%	303	$3,028,639
4	10,000	908	90%	3%	3	$27,244
Total	**29,000**	**297,826**	**NA**	**NA**	**2,711**	**$12,809,136**

1. Source: PHMSA Best Professional Judgment
2. Source: PHMSA 2014 Annual Report via PDM
3. Calculated as total mileage × (100% - current compliance) × incremental need for surveys.
4. Calculated as compliance mileage × unit cost.

3.4.4.4 Internal Corrosion Monitoring

As a matter of routine business practice, such as monitoring gas quality for meeting tariff specifications, many operators already have monitors at gas entry points to their systems. Many interstate pipeline companies have continuous monitoring of gas quality. PHMSA used BPJ to estimate the costs of this provision, as shown in **Table 3-75**. The analysis of the data, depending on how it is recorded, would also be relatively inexpensive since an engineer would only have to review the data quarterly and look for trends or out of specification components. Thus, the added cost of monitoring for CO_2, sulfur, water, and other chemicals is either nothing or relatively inexpensive.

Table 3-75. Estimation of Costs for Internal Corrosion Monitoring					
Class	**Monitoring Equipment Cost**	**Total Number of Monitors Needed**	**% Current Compliance**	**Number of Monitors for Compliance**	**Costs**
1	$10,000	250	95%	13	$125,000
2	$10,000	50	80%	10	$100,000
3	$10,000	150	95%	8	$75,000
4	$10,000	200	95%	10	$100,000
Total	**NA**	**650**	**NA**	**40**	**$400,000**

Source: PHMSA Best Professional Judgment
1. Calculated as total number of monitors needed × (100% - % current compliance).

3.4.4.5 Total Corrosion Control Costs

Table 3-76 summarizes the incremental compliance costs for the expansion of corrosion control. **Table 3-77** provides the present values over the 15-year study period.

Table 3-76. Summary of Incremental Costs, Corrosion Control (Millions)			
Component	**One-Time**	**Annual**	**Recurring (7 years)**
External Corrosion Coatings	$0	$0.3	$0
External Corrosion Monitoring	$4.0	$6.6	$0
Interference Current Surveys	$0	$0	$12.8
Internal Corrosion Monitoring	$0.4	$0	$0
Total	**$4.4**	**$6.9**	**$12.8**

Table 3-77. Present Value Incremental Costs, Topic Area 4[1]			
Total (7%)	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
$94,788,018	$6,319,201	$118,451,243	$7,896,750

1. Calculated assuming one-time costs in year 1; annual costs in years 1-15; and 7-year recurring costs annualized over 7 years at the different discount rates. Total is present value over 15 years; average annual is total divided by 15.

3.5 PIPELINE INSPECTION FOLLOWING EXTREME EVENTS

This topic area includes the following changes:

1. Continuing surveillance to also include other unusual operating and maintenance conditions, including changes resulting from extreme weather or natural disasters, and other similar events [§ 192.613]
2. Inspection (within 72 hours) and remedial action following extreme weather, man-made, or natural disasters, and other similar events. [§ 192.613(c)]

3.5.1 PROBLEM STATEMENT

Currently, 49 CFR § 192.613 prescribes general requirements for continuing surveillance of a pipeline to determine and take appropriate actions needed due to changes in the pipeline from, among other things, unusual operating and maintenance conditions. Weather-induced movement of the pipeline resulting in coating damage, abrasion and gouging, fatigue cracking, and subsequently failure caused a 2009 incident on an offshore pipeline. The

probable cause of the 2011 hazardous liquid pipeline incident resulting in a crude oil spill into the Yellowstone River near Laurel, Montana was scouring at a river crossing due to flooding.

Based on recent examples of extreme weather events that resulted, or could have resulted, in pipeline incidents, PHMSA has determined additional requirements are needed to assure that operator procedures adequately address inspection of the pipeline and right-of-way for "other factors affecting safety and operation" following extreme weather events and natural disasters, and other similar events. Such inspections would apply to both onshore and offshore pipelines and their rights-of-way. The proposed rule would amend § 192.613(a) accordingly. In addition, the proposed rule would add a new paragraph, § 192.613(c), to require such inspections, specify the timeframe in which such inspections must be performed, and specify that appropriate remedial actions must be taken to ensure safe pipeline operations.

3.5.2 ASSESSMENT OF REGULATORY IMPACT

The proposed rule would specify that operators conduct surveillances following extreme weather or natural disaster, or similar events. Inspections would be required within 72 hours, or as soon as possible, when personnel with the equipment required for inspecting the pipeline can safely access the affected area. Additionally, the proposed revisions would require remedial actions when adverse conditions are identified.

3.5.3 ANALYSIS ASSUMPTIONS

PHMSA assumed that most operators already have right-of-way inspection, surveillance, and leakage survey procedures to monitor for conditions meeting the proposed requirements. These procedures would require minor revisions to include the proposed requirements in § 192.613. These clarifications would specify that operators must conduct surveillances following extreme weather or natural disaster, or similar events within 72 hours of the cessation of an event or as soon as possible once personnel and equipment can safely access the affected area. PHMSA notes that all operators are currently required to take remedial or mitigative measures upon discovery of an unsafe condition. As such, the analysis does not consider cost associated with remediation of damage due to the event. The cost and benefit of this proposed requirement is that it sets a standard for timely inspection and surveillance of pipelines in the wake of an extreme event, in order to discover damage caused by the event before the pipeline fails in service.

Most gas transmission operators would need to update their existing surveillance and patrol procedures. PHMSA assumed that approximately 50 percent of operators would need only minor revisions to their procedures and programs and 50 percent may require a more substantial effort to update programs to address extreme events.

3.5.4 ESTIMATION OF COSTS

PHMSA used BPJ to estimate the costs of this provision as shown in **Table 3-78**.

Table 3-78. Estimation of Costs for Process Development for Extreme Events

Activity	Hours (Low)	Hours (High)	Cost per Operator (Low)[1]	Cost per Operator (High)[1]	Total Cost (Low)[2]	Total Cost (High)[2]	Total Cost (Average)
Review existing	2	1	$198	$99	$100,683	$50,342	$75,512

Activity	Hours (Low)	Hours (High)	Cost per Operator (Low)[1]	Cost per Operator (High)[1]	Total Cost (Low)[2]	Total Cost (High)[2]	Total Cost (Average)
surveillance and patrol procedures to validate adequacy for extreme events							
Revise surveillance and patrol procedures	5	20	$495	$1,980	$251,708	$1,006,830	$629,269
Notify involved personnel of new procedures, providing implementation guidance and instruction	5	10	$495	$990	$251,708	$503,415	$377,561
Total	**12**	**31**	**$1,188**	**$3,069**	**$604,098**	**$1,560,587**	**$1,082,342**

Table 3-78. Estimation of Costs for Process Development for Extreme Events

Source: PHMSA best professional judgment
1. Calculated as hours × labor cost for senior engineer ($99; see Table 3-66).
2. Calculated as cost per operator × 50% × 1,017 operators.

PHMSA used the average cost value above to estimate the present value of compliance costs as shown in **Table 3-79**.

Table 3-79. Present Value Costs, Topic Area 5[1]

Total (7%)	Average Annual (7%)	Total (3%)	Average Annual (3%)
$1,082,342	$72,156	$1,082,342	$72,156

1. Total is present value over 15 year study period; average annual is total divided by 15 years.

3.6 MAOP EXCEEDANCE REPORTS AND RECORDS VERIFICATION

This topic area includes the following proposed changes to 49 CFR Part 192:

1. New mandatory reporting of MAOP exceedances [§ 191.1, § 191.23]
2. New requirement for operations and maintenance (O&M) procedures to assure MAOP is not exceeded by amount needed for overpressure protection [§ 192.605(b)(13)]
3. New requirements for verification of MAOP-related records and clarification of records preparation and retention requirements [§ 192.619(f), §192.13(e), Appendix A].

3.6.1 PROBLEM STATEMENT

This section discusses the need for each of the changes.

Reporting of MAOP Exceedances

Section 23 of the Act requires that operators report each exceedance of the MAOP beyond the build-up allowed for operation of pressure-limiting or control devices. The proposed rule would codify this statutory requirement.

On December 21, 2012, PHMSA published Advisory Bulletin ADB-2012-11, to advise operators of their responsibility under Section 23 of the Act to report such exceedances. The

advisory bulletin further stated:

> This reporting requirement is applicable to all gas transmission pipeline facility owners and operators. In order to comply with this self-executing provision, PHMSA advises owners and operators to submit this information in the same manner as SRC reports. The information submitted by owners and operators should comport with the information listed in § 191.25(b), and the reporting methods listed in § 191.25(a) should be employed.
>
> The reporting exemptions for SRC reports listed in § 191.23(b) do not apply to the reporting requirement for exceedance of MAOP plus build-up. Specifically, § 191.23(b)(4), which allows for non-reporting if the SRC is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the SRC report, does not apply. Gas transmission owners and operators must report the exceedance of MAOP plus build-up regardless of whether the exceedance is corrected before five days have passed.
>
> Finally, owners and operators have five days after occurrence to report exceedance of MAOP plus build-up.

Even though this provision of the Act is self-executing, PHMSA proposes to revise 49 CFR 191.23 to codify this requirement and provide consistent procedure, format, and structure for submittal of such reports by all operators.

The reporting requirements for exceedance of MAOP plus build-up currently exist in Part 191 and the only change involves deletion of the reporting exemption for exceedance of MAOP for transmission lines in cases where the condition is corrected within five days, in order to conform to the statutory mandate. Operators were required to begin reporting MAOP exceedances, and have been doing so, since 2012. Forty such reports have been received by PHMSA as of the date of this report.

Prior to the statute, operators were already required to report such exceedances as specified in 49 CFR 191.23. However, actual filing of the report was not required if the condition was corrected before expiration of the reporting deadline. In effect, this requires that all such exceedances be reported, instead of only those that are not corrected within the 10-day reporting deadline. Because of this existing requirement, operators already have procedures and processes in place to identify, document, and report such exceedances. This rule would merely require the actual filing of the reports, which previously might not have to be filed.

<u>O&M Procedures</u>
Implicit in the proposed requirements of 49 CFR 192.605 is the intent for operators to establish operational and maintenance controls and procedures to effectively preclude operation at pressures that exceed MAOP. PHMSA expects that operators' procedures should already address this aspect of operations and maintenance, as it is a long-standing, critical aspect of safe pipeline operations. However, § 192.605 does not explicitly prescribe this aspect of the procedural controls, which is added to § 192.605(b)(13). Since this change is a clarification of existing requirements, this requirement does not impose an additional cost burden on pipeline operators.

MAOP Records Verification

49 CFR § 192.603(b) prescribes the general requirement to maintain records for operating, maintaining, and repairing the pipeline in accordance with each of the O&M requirements of 49 CFR Part 192, Subparts L (operations) and M (maintenance). Subpart L (specifically § 192.619) prescribes requirements for establishing the MAOP of the pipeline. Section 23 of the Act requires that operators verify the existence and sufficiency of records used to confirm MAOP. The purpose of the verification is to ensure that the records accurately reflect the physical and operational characteristics of the pipelines and to confirm the established MAOP of the pipelines. The Act requires the verification to be completed within six months following enactment of the Act. PHMSA issued Advisory Bulletin 11-01 on January 10, 2011 (76 FR 1504) and Advisory Bulletin 12-06 on May 7, 2012 (77 FR 26822) to inform operators of this required action. Advisory Bulletin 12-06 further stated:

> As directed in the Act, PHMSA would require each owner or operator of a gas transmission pipeline and associated facilities to verify that their records confirm MAOP of their pipelines within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in HCAs.
>
> PHMSA intends to require gas pipeline operators to submit data regarding mileage of pipelines with verifiable records and mileage of pipelines without records in the annual reporting cycle for 2013. On April 13, 2012, (77 FR 22387) PHMSA published a Federal Register Notice titled: ''*Information Collection Activities, Revision to Gas Transmission and Gathering Pipeline Systems Annual Report, Gas Transmission and Gathering Pipeline Systems Incident Report, and Hazardous Liquid Pipelines Systems Incident Report.*'' PHMSA plans to use information from the 2013 Gas Transmission and Gathering Pipeline Systems Annual Report to develop potential rulemaking for cases in which the records of the owner or operator are insufficient to confirm the established MAOP of a pipeline segment within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in HCAs. Owners and operators should consider the guidance in this advisory for all pipeline segments and take action as appropriate to assure that all MAOP and MOP are supported by records that are traceable, verifiable and complete.

As discussed above, the requirement for verification of records used to establish MAOP is mandated in Section 23 of the Act and articulated by PHMSA in Advisory Bulletin 11-01 and reiterated in Advisory Bulletin 12-06. In addition, documentation of verification records used to establish MAOP is required in the annual reporting cycle for 2013.

PHMSA has determined additional rules are needed to implement this requirement of the Act and ensure that future records used to establish MAOP are reliable, traceable, verifiable, and complete. The proposed rule would add new paragraphs §§ 192.13(e) and 192.619(f), to codify this requirement, to elaborate on the general recordkeeping requirement in § 192.603 with respect to records used to establish MAOP, and to require that such records be retained for the life of the pipeline. The statutory mandate to complete and report on verification of records used to establish MAOP in 2013 must be completed before the proposed rule would be promulgated (in fact, such reporting was completed as of June 30, 2013).

PHMSA has determined that an important aspect of compliance with MAOP records verification requirements is to assure that records that demonstrate compliance with Part 192 are complete and accurate. The proposed rule would add new paragraph § 192.13(e) to more clearly articulate the requirements for records preparation and retention and to require that records be reliable, traceable, verifiable, and complete. The proposed new 49 CFR Part 192 Appendix A would provide specific requirements for records retention. These changes are clarifications of requirements only. Proposed § 192.619(f) would require operators to maintain records that establish the pipeline MAOP, which include but are not limited to design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data.

3.6.2 ASSESSMENT OF REGULATORY IMPACT

As discussed in Section 3.6.1 above, operators are in compliance with the proposed requirements in this topic area. PHMSA assessed the regulatory impact from the prestatutory baseline. That is, PHMSA estimated the cost of meeting these requirements.

3.6.3 ANALYSIS ASSUMPTIONS

PHMSA based estimation of the incremental cost of this provision on the burden estimates in the applicable Information Collection Requests (ICRs).

3.6.4 ESTIMATION OF COSTS

PHMSA used Safety Related Condition (SRC) and annual report data, the estimates of burden in the ICRs for the SRC and Gas Transmission Annual Report, and the labor rates in Table 3-66, deflated to year dollars incurred, to estimate costs of compliance.

Reporting of MAOP Exceedances

Section 23 of the Act requires that operators report each exceedance of the MAOP beyond the build-up allowed for operation of pressure-limiting or control devices. **Table 3-80** summarizes the number of MAOP exceedance SRC reports on gas transmission pipelines.

Table 3-80. MAOP Exceedence Reports from Gas Facilities

Year	MAOP Exceedance Reports
2012	5
2013	21
2014	21
2015	17
Source: PHMSA Safety Related Condition Reports: MAOP exceedance reports on gas transmission pipelines	

On average operators submitted 16 MAOP exceedance reports per year. The most recent supporting statement for the SRC ICR indicates each SRC takes approximately six hours to complete.[30] Based on the fully loaded labor rate of $99 per hour for a senior mechanical engineer (see Table 3-66), the average annual cost for MAOP reporting is $9,500.

MAOP Records Verification

Operators incurred a cost to complete a MAOP records review and report that information to PHMSA on annual reports. PHMSA assumed that operators incur a burden to complete

[30] http://www.reginfo.gov/public/do/PRAViewICR?ref_nbr=201405-2137-001

initial records checks and then negligible costs thereafter. In the supporting statement for the Gas Transmission Annual Report ICR, PHMSA estimated that it would take operators approximately 20 hours to complete records checks for 1,440 reports. [31] PHMSA estimated one-time costs of $2.9 million based on a fully loaded labor rate of $99/hr. (Table 3-66).

Summary of Costs for MAOP Exceedance Reporting and Records Verification
PHMSA assumed that operators have already completed records verification and MAOP exceedance reporting from 2012 to 2015. For this analysis, PHMSA deflated costs that occurred in the past using the CPI.

Table 3-81. Previously Incurred Compliance Costs (2015$)

Year	MAOP Exceedance Reporting[1]	Records Verification	Total at Current Labor Rates	Estimated Cost Incurred[3]
2012	$2,970	$2,851,200[2]	$2,854,170	$2,764,781
2013	$12,474	$0	$12,474	$12,260
2014	$12,474	$0	$12,474	$12,459
2015	$10,098	$0	$10,098	$10,098
Total	$38,016	$2,851,200	$2,889,216	$2,799,598

NA = not applicable
1. Reports from Table 3-80 times six hours times $99/hour labor rate from Table 3-66.
2. 1,440 reports times 20 hours times $99/hour labor rate from Table 3-66.
3. Cost at labor rates in year occurred approximated using the Bureau of Labor Statistics Consumer Price Index – All Urban Consumers (average annual value for 2015: 237.0; 2014: 236.7; 2013: 233.0; 2012: 229.6).

Table 3-82 summarizes the discounted compliance costs for MAOP exceedance reporting and records verification assuming a pre-statutory baseline.

Table 3-82. Present Value Costs, Topic Area 6 (2015$)[1]

Total (7%)	Average Annual (7%)	Total (3%)	Average Annual (3%)
$2,892,219	$192,815	$2,916,460	$194,431

1. Total is present value over 15 year study period; average annual is total divided by 15 years.

3.7 LAUNCHER/RECEIVER PRESSURE RELIEF

This topic area includes the addition of the following safety features on launchers and receivers [§ 192.750]:

1. Require pressure relief device, and
2. Require pressure reading device, or prevention of opening while pressurized.

3.7.1 PROBLEM STATEMENT

Fatalities and injuries have occurred due to operation of pig launchers and receivers. For example, on June 25, 2012, one worker was killed and two more were injured at a BP America Production Company Facility caused by incorrect operation leading to overpressure and failure of a pig launcher.[32] The facility was not equipped with a pressure

[31] http://www.reginfo.gov/public/do/PRAViewICR?ref_nbr=201209-2137-001, operators may have to submit multiple reports
[32] https://www.rmecosha.com/ndakotastanddown/BP_Industry_Safety_Alert.pdf

relief valve.

PHMSA has determined that more explicit requirements are needed for safety when performing maintenance activities that utilize launchers and receivers for inserting and removing maintenance tools and devices. Such facilities are subjected to pipeline system pressures. Current regulations for hazardous liquid pipelines (49 CFR Part 195) have, since 1981, contained such safety requirements for scraper and sphere facilities (§ 195.426). However, current regulations for gas pipelines (49 CFR Part 192) do not similarly require controls or instrumentation to protect against inadvertent breach of system integrity due to incorrect operation of launchers and receivers for inline inspection tools, scraper, and sphere facilities. Accordingly, the proposed rule would add a new section, § 192.750, to require a suitable means to relieve pressure in the barrel and either a means to indicate the pressure in the barrel or a means to prevent opening if pressure has not been relieved.

3.7.2 ASSESSMENT OF REGULATORY IMPACT

The regulatory impact of rulemaking requiring the addition and use of new safety features when performing maintenance activities using launchers and receivers is minor due to the current widespread use of such safety measures. The use of safety measures such as pressure relief valves, pressure reading devices, and procedures that do not allow the opening of launchers and receivers while pressurized is already standard industry practice. Thus, the likelihood that these safety devices have been installed and precautionary procedures put in place has increased. Additionally, it is likely that information and lessons learned regarding past incidents and near misses involving launchers and receivers have been shared among operators and in industry forums due to the potential danger to workers.

3.7.3 ANALYSIS ASSUMPTIONS

Section 3.7.4 provides a detailed analysis of the estimated cost of these proposed changes is presented in. The key assumptions used in the analysis are:

- Almost all installed launchers and receivers already utilize safety devices.
- Less than 10 legacy launchers or receivers would require installation of new safety devices.
- 50% of the installations are to be on lines 16 inches in diameter or less; the remainder on line sizes greater than 16 inches in diameter.
- The ten launchers or receivers requiring modification would involve ten separate pipeline operators.
- Regardless of the proposed rulemaking, the design and construction of future launchers and receivers would incorporate these safety features, as part of standard industry practices currently in use.

The proposed rule would specify that the new safety devices be installed within six months of the effective date of the new section § 192.750.

3.7.4 ESTIMATION OF COSTS

PHMSA used BPJ to estimate the cost of creating specifications (design, installation, and testing) for pressure relief systems for launcher/receiver facilities, as shown in **Table 3-83.**

Table 3-83. Estimation of Costs for Creating Launcher and Receiver Pressure Specifications				
Activity	**Hours**	**Cost[1]**	**Number of Systems**	**Total Cost**
Review existing design, installation, and testing specifications for launcher/receiver facilities.	1	$99	10	$990
Revise specifications to comply with new §192.750.	24	$2,376	10	$23,760
Total	**25**	**$2,475**	**10**	**$24,750**
Source: PHMSA best professional judgment 1. Calculated as hours × labor cost for senior engineer ($99; see Table 3-66).				

PHMSA used BPJ to estimate the cost of designing, installing, and testing a pressure relief system for launcher/receiver facilities, as shown in **Table 3-84**.

Table 3-84. Estimation of Costs for Launcher and Receiver Safety Device Installation					
Component	**Cost per Small Line[1] (<16")**	**Cost per Large Line[2] (>16")**	**Incremental Number of Devices, Small Lines**	**Incremental Number of Devices, Large Lines**	**Total Cost**
Closure	$7,000	$25,000	5	5	$160,000
Trap	$10,000	$25,000	5	5	$175,000
Total	**$17,000**	**$50,000**	**10**	**10**	**$335,000**
Source: PHMSA best professional judgment 1. Pressure relieving closure for 8" line size with 12" trap including installation and testing. 2. Pressure relieving closure for 30" line size with 36" trap including installation and testing.					

The total one time cost of this action is the sum of the two total values above, which equals $359,750.

3.8 EXPANSION OF GAS GATHERING REGULATION

Topic Area 8 includes the following proposed regulatory changes:

1. Revise the current definition of a gas gathering line; establish new, first-time definitions for onshore production facility or onshore production operation, gas processing plant, and gas treatment facility; and repeal the use of American Petroleum Institute (API) Recommended Practice (RP) 80 as the regulatory basis for identifying regulated onshore gas gathering lines. [§ 192.3]
2. Expand the scope of regulated onshore gas gathering lines to include lines in Class 1 locations that operate at greater than or equal to 20% of SMYS and which are greater than or equal to 8" in diameter. These lines would become subject to a subset of regulatory requirements (corrosion protection, damage prevention, and certain other safety provisions). [§ 192.8, § 192.9]
3. Repeal the current exemption to file reports for certain gas gathering lines in accordance with 49 CFR Part 191. The proposed rule would require that operators of

all gas gathering lines be subject to the following:

a. immediate notice of incidents [§ 191.5];
b. reporting of incidents [§ 191.15];
c. reporting of safety related conditions (SRCs) [§ 191.23];
d. reporting of annual pipeline summary data [§ 191.17]; and
e. reporting to PHMSA's National Registry of Pipeline Operators [§ 191.22].

Section 3.8.1, 3.8.2, and 3.8.3 address each of these three regulatory changes separately.

3.8.1 REVISE THE DEFINITION OF GAS GATHERING LINE

This section addresses the gas gathering line definition.

3.8.1.1 Problem Statement

Inspection and enforcement of the current regulatory requirements for regulated gas gathering lines is hampered by the conflicting and ambiguous language of API RP 80, a complex recommended practice that can produce multiple interpretations for the same gathering pipeline system. This practice has led to the classification of gas gathering lines in ways that were not intended when API RP 80 was adopted by PHMSA in 2006.[33] This ambiguity could result in some gas gathering lines being operated out of compliance with PHMSA's pipeline safety regulations resulting in increased risk to the public, workers, and the environment.

The proposed rule would repeal use of API RP 80 as the basis for identifying regulated onshore gas gathering lines and would establish new definitions for 'onshore production facility or onshore production operation,' 'gas processing plant,' and 'gas treatment facility,' and a revise the definition for 'gathering line,' to determine the beginning and endpoints of each onshore gas gathering line. The proposed rule would not reference API RP 80 definitions for gathering lines or gathering line categories.

3.8.1.2 Assessment of Regulatory Impact

The proposed revised definition for "gathering line" is a clarification of the existing requirement, although the classification of some gathering lines may change as a result. The definition is consistent with the original intent of the 2006 rulemaking. Pipelines commonly referred to as "farm taps," serving residential, commercial, or industrial customers, would not meet the revised gathering line definition and would continue to be classified as either transmission or distribution lines.

Compliance costs for gas gathering pipeline operators would be negligible because a relatively small amount of mileage for each operator in comparison to their total regulated mileage would be involved; some of these costs would be offset by lowered compliance costs when some lines are newly excluded from PHMSA regulation; and incremental costs for any new requirements would also be partially offset by activities already undertaken in accordance with existing industry practice.

[33] *Ibid*. 10

3.8.2 EXPAND THE SCOPE OF REGULATED ONSHORE GATHERING LINES

This section addresses the expansion of the scope of regulated gas gathering lines.

3.8.2.1 Problem Statement

Since 2007 the oil production in the United States has surged 71%, while natural gas production has grown nearly 30%,[34] due to breakthroughs in extraction technologies. Development of shale oil deposits and tight gas production is altering not just the extent, but also the characteristics of the nation's gas transmission and gathering systems. New gas fields are being developed in new geographic areas, requiring entirely new gas gathering systems and networks of new gas gathering lines.

Producers are employing gathering lines with larger diameters and/or higher operating pressures to support the new high volume production wells, with higher throughputs of gas. Gathering lines are being constructed as large as 36 inches in diameter with maximum operating pressures up to 1480 psig. These characteristics far exceed past design and operating parameters of typical gathering lines.

Most of these new gas gathering lines are unregulated and PHMSA does not collect incident data or annual report data on these unregulated lines. However, PHMSA is aware of incidents indicative that these lines are subject to the same sorts of failure modes common to other pipelines that PHMSA does regulate. For example, on November 14, 2008, three homes were destroyed and one person injured when a gas gathering line exploded in Grady County, Oklahoma. On June 8, 2010, two workers died when a bulldozer struck a gas gathering line in Darrouzett, Texas. On June 29, 2010, three men working on a gas gathering line in Grady County, Oklahoma were injured when it exploded.

The dramatic expansion in natural gas production and changes in typical gathering line characteristics requires PHMSA to review its regulatory approach to gas gathering pipelines to address safety and environmental risk.

A 2014 GAO report recommends[35] PHMSA address the increased risk posed by new larger-diameter, higher-pressure gas gathering pipelines. The National Association of Pipeline Safety Representatives (NAPSR) Resolution No. 2010-2 AC-2[36] also supports regulating additional, currently unregulated onshore gas gathering lines. Consistent with the NAPSR Resolution, PHMSA is proposing to regulate the operation of gas gathering pipelines that:

(1) Are located in a Class 1 location, and
(2) Operate at MAOP ≥ 20% SMYS, and
(3) Are ≥ 8 inches in diameter.

The proposed new category of regulated lines would be designated Type A, Area 2. Type A, Area 2 gas gathering line segments would be subject to the following subset of 49 CFR Part

[34] Energy Information Administration, "Crude Oil Production," and "Natural Gas Production: Gross Withdrawals," retrieved April 9, 2014. www.eia.gov.
[35]GAO Report GAO-14-667, "*Oil and Gas Transportation, Department of Transportation is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to Improve Pipeline Safety*,' August 2014. p. 48.
[36] Letter from Danny McGriff, National NAPSR Chair, Georgia Public Service Commission, to Jeffrey D. Wiese, Associate Administrator, Pipeline and Hazardous Materials Safety Administration, dated November 1, 2010, *Resolutions Passed during 2010 NAPSR National Meeting*

192 regulatory requirements:

(1) For new, replaced, relocated, or otherwise changed lines, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of Part 192;
(2) For metallic pipelines, corrosion must be controlled in accordance with the requirements of Part 192, Subpart I ;
(3) A damage prevention program must be conducted under § 192.614;
(4) An emergency plan must be established and implemented under § 192.615;
(5) A public awareness program must be conducted under § 192.616;
(6) The MAOP of the lines must be established under § 192.619; and
(7) Line markers must be installed and maintained in accordance § 192.707.

The proposed regulation focuses on preventive measures for the most frequent causes of failure (corrosion and excavation damage) and on emergency preparedness. Minimum federal safety standards would bring an appropriate level of consistency to the current mix of regulations that differ from state to state.

3.8.2.2 Assessment of Regulatory Impact

The regulatory impact of the proposed rule is the mandatory application of a subset of requirements in 49 CFR Part 192 that apply to gas transmission lines to a substantial amount of currently unregulated gas gathering pipelines. The impact is limited to higher-risk lines (i.e., larger lines that operate at higher pressures) and the most likely causes and impacts of pipeline failure.

3.8.2.3 Analysis Assumptions

Compliance costs for the proposed regulation depend on the extent to which operators already comply. Many operators are already subject to the proposed regulations since they operate other regulated pipeline segments and already have safety programs in place for compliance. Some of these operators may already apply their relevant safety programs to their unregulated gathering pipelines as a matter of good business practice. Additionally, many states already require some of the provisions included in the proposed rule (e.g., state damage prevention laws) so operators won't incur substantial additional compliance costs. These factors are described more fully in Section 3.8.2.4. For this analysis, PHMSA assumed that many operators already substantially comply with some portions of the proposed rule.

3.8.2.4 Estimation of Costs

PHMSA analyzed two groups of operators: those not currently operating regulated gas pipelines (group 1) and those currently operating regulated gas pipelines (group 2). Costs to operators in group 2 are likely less because these operators already perform all of the requirements and costs would be limited to the inclusion of additional mileage under existing regulatory compliance programs.

The steps to estimate costs are:

1. Estimate the unit cost ($/mile) for implementing each specific requirement.
2. Estimate mileage of gas gathering pipelines that would be newly regulated.
3. Multiply unit costs by mileage to obtain total incremental compliance costs.

3.8.2.4.1 Estimation of Unit Costs

The Independent Petroleum Association of America (IPAA)[37] provided cost information for a 2006 rulemaking. The 2006 rule included five provisions common to this proposed rulemaking:

1. Initial population survey and periodically recurring population surveys.
2. Initial capital costs and annually recurring costs for corrosion control programs.
3. Initial capital costs and annually recurring costs for line markers and line marker maintenance.
4. Annually recurring costs for damage prevention programs.
5. Annually recurring costs for public education programs.

The unit cost assumptions in the 2006 RIA are shown in **Table 3-85**, updated to current year dollars. The sections below describe the BPJ adjustments PHMSA made to these unit costs for analysis of each provision of the proposed rulemaking.

Table 3-85. Unit Cost of 2006 Expanded Safety Provisions ($ per mile)

Component	Initial Capital Cost (2006$)[1]	Operating (Recurring) Costs (2006$)[1]	Initial Capital Cost (2015$)[2]	Operating (Recurring) Costs (2015)[2]
Population survey	$588	$118	$642	$129
Corrosion control	$17,183	$449	$18,751	$490
Line markers	NA	$153	NA	$166
Damage prevention	NA	$259	NA	$282
Public education	NA	$198	NA	$216

1. Source: IPAA, as cited in PHMSA, 2006, Final Regulatory Evaluation, Regulated Natural Gas Gathering Lines.
2. Updated from 2006 dollars using the BLS All-City Consumer Price Index, averaged through November (2006 CPI: 201.6; 2015 CPI: 237.0)

<u>Population Surveys</u>

For the proposed rule there should be little, if any, costs associated with initial surveys. The 2006 Gas Gathering Rule required surveys for all gathering pipelines to determine if each pipeline is regulated or unregulated. The results of those surveys can largely be used for the proposed rule.

Additional periodic survey (continuing surveillance) costs may be incurred. For operator that do not run existing continuing surveillance programs (group 1), PHMSA used 100% of the IPAA estimate.

For operators that do run existing continuing surveillance programs (group 2), PHMSA expects that the additional costs of adding mileage to ongoing surveillance programs would be less. Routine observation during the normal course of operations and maintenance is expected to detect many (if not all) of the potential changes in class location that are the focus of this proposed requirement. Changes in class location involve, for example, the

[37] U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Final Regulatory Evaluation, Regulated Natural Gas Gathering Lines, Docket RSPA-1998-4868.

readily-detectable construction of new buildings near pipeline rights-of-way. PHMSA estimated the unit cost to operators in group 2 to add gathering line mileage to their existing continuing surveillance programs to be 25% of the IPAA estimate.

Corrosion Control

PHMSA estimated that initial capital start-up costs to implement corrosion control for group 1 operators are 100% of the IPAA estimates of one-time and recurring costs.

If an operator already has a corrosion control program for other, regulated lines (group 2), then costs are expected to be less due to expertise and resources already dedicated to this aspect of an operator's business. However, substantial initial capital costs for procurement and installation of corrosion control equipment would still be required for currently unprotected lines. In those cases, PHMSA estimated start-up and recurring costs are 75% of the IPAA estimate for lines not currently under cathodic protection.

Where cathodic protection already exists on currently unregulated gathering lines (both group 1 and 2), PHMSA assumed substantially compliant corrosion control programs also exist. For those cases, essentially all of the capital equipment and most, but possibly not all, of the recurring corrosion control elements that would be required are assumed to be already in place. Thus, there should be no significant start-up capital costs, and recurring costs are estimated to be approximately 5% of the IPAA estimate.

Line Markers

Operators of currently regulated gathering lines (group 2) must already place and maintain line markers for buried lines in accordance with requirements under §192.707. They should, for all practical purposes, have developed programs to ensure that those requirements are met, to manage line marker maintenance (likely done in part during right-of-way surveillance), and to ensure line markers are installed as required for new lines. This would include related elements such as marker specifications.

Operators not currently operating regulated gathering lines (group 1) may or may not have similar programs in place. For these operators, PHMSA used the recurring maintenance cost estimate of 100% of the original IPAA estimate. This would include the initial cost to an operator of developing and documenting a line marker program, as well as initially specifying, procuring, and installing the markers.

For operators already having regulated assets (group 2) PHMSA assumes that costs are 50% of the IPAA estimate. As noted, these operators will not incur additional costs to develop their line marker programs and should already have the majority of their line markers in place. The only additional costs should come from adding newly-regulated lines to their programs, and procuring and installing additional markers.

Damage Prevention Programs

The original estimate provided by IPAA included the initial costs to an operator for developing and documenting a new program, and implementing the program. However, operators of currently regulated gathering lines (group 1) must already have and carry out written excavation damage prevention programs in accordance with requirements under § 192.614. Section 192.614(b) requires a regulated operator to comply with the requirements of § 192.614(c) through participation in a qualified one-call system where there is one in

place. Operators that have any regulated gathering lines (i.e., group 1) should already have and implement those programs to ensure that the requirements are met.

In addition, all States have excavation damage prevention laws in place. The requirements for pipeline operators under State one-call laws address to a large extent the requirements of § 192.614. These laws, with few exceptions, require underground facility operators to participate in the one-call system(s) within the state. Through the one-call system an operator will be notified when an excavator plans to excavate near the operator's lines. The operator must then locate and mark the lines to prevent them from being damaged during excavation. PHMSA is not aware of any states that exempt gathering lines from state damage prevention laws (i.e., both group 1 and group 2 operators must comply with State damage prevention laws).

Thus, all gathering line operators (whether or not they operate gathering lines regulated under Part 192) already have to adhere to State laws to meet those requirements and costs to operators of the proposed rule in this regard is believed to be minimal. Therefore, for this analysis, PHMSA assumed a weighted average recurring cost to all gathering line operators across all states of 5% of the IPAA estimate to account for the cost of developing and maintaining a written damage prevention program (a written program description is not typically required by State laws) for operators in group 1, or to add additional lines to its existing program documentation for operators in group 2.

Public Education (Awareness) Programs

PHMSA assumed 100% of the IPAA estimate for the recurring costs of the proposed requirement would apply for each newly-regulated gathering pipeline operator (group 1). However, 49 CFR § 192.616 requires that all currently regulated gas gathering pipeline operators must develop and implement a written continuing public education program that follows the guidance provided in API RP 1162. Operators of currently regulated gathering lines (group 2) have developed and continue to implement those programs. For these operators, PHMSA assumed incremental costs for the proposed requirement to be 10% of the IPAA estimate.

Establishing MAOP

Consistent with the regulatory analysis for the 2006 rulemaking,[38] establishing MAOP does not require significant physical work along the pipeline. Instead, this involves a review of pipeline records to identify the pressures to which the pipeline was tested and/or at which it has operated.[39] These costs are incurred for major portions of each pipeline system rather than on a per-mile basis. For many pipelines, no new costs would be required, since an MAOP would already have been determined or easily established using previous operating pressures. For other pipelines, these costs would be primarily administrative in nature, and very small as a result. Therefore, PHMSA assumed the total costs for this requirement would be negligible.

Design, Installation, and Testing of New, Replaced, Relocated, or Changed Lines

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[38] *Ibid*. 33

[39] The newly regulated onshore gathering lines would be allowed to establish MAOP in accordance with 192.619(c), commonly referred to as the "grandfather clause," which allows the operator to use the highest actual operating pressure experienced in the five years prior to the effective date of the proposed rule as the MAOP.

The compliance costs for new, replaced, or changed pipelines are insignificant because operators would be able to account for compliance with PHMSA requirements as part of the decision-making and planning process. Typical industry construction practices follow industry standards and are already very similar to PHMSA's design and construction regulations. The primary differences in the design, testing, and record keeping phases are minor compared to the more expensive right-of-way, material acquisition, and installation phases that constitute the vast majority of the total construction costs. Therefore, incremental compliance costs associated with this new requirement are negligible relative to the other estimated costs.

Compliance for Emergency Preparedness

The proposed rule would require gas gathering operators to develop a written emergency plan in compliance with § 192.615. PHMSA conservatively estimated the cost to develop and implement emergency plans for each newly-regulated gathering line operator (group 1) is $325/mile/year.

Any operator with a currently regulated Type A gas gathering line or any gas transmission line segments (group 2) is already required to have such a program for those segments. In such cases, the operator would need to review and expand (if needed) existing plans to address additional pipeline segments. The cost for group 2 operators that only need to review/expand existing plans is estimated to be approximately $20/mile/year.

Summary of Unit Costs of Compliance

Table 3-86 summarizes the estimated unit costs of compliance as discussed above.

Table 3-86. Summary of Estimated Unit Costs, Unregulated Onshore Gas Gathering Pipelines			
	Operators of Currently Unregulated Lines (Group 1)	**Operators of Currently Regulated Lines (Group 2)**	**Operators of Lines with Cathodic Protection Subject to Damage Prevention Laws**
One-Time Capital			
Corrosion Control	$17,183	$12,887	$0
Recurring (7 years)			
Population Surveys	$118	$29	NA
Recurring – Annual			
Corrosion control	$449	$337	$22
Line markers	$153	$76	NA
Damage prevention	$259	$129	$13
Public awareness	$198	$20	NA
MAOP	$0	$0	NA
Design, installation, testing	$0	$0	NA
Emergency plan	$325	$20	NA
Source: PHMSA best professional judgment percentage adjustment (see text) of inflation-adjusted IPAA (2006) cost information.			

3.8.2.4.2 Estimation of Newly-Regulated Mileage

PHMSA currently regulates approximately 11,400 miles of onshore gas gathering pipelines, as shown in **Table 3-87**.

Table 3-87. Currently Regulated Onshore Gas Gathering Infrastructure		
Type A Miles	**Type B Miles**	**Total Miles**
7,844	3,580	11,424
Source: 2014 Gas Gathering Annual Report		

Onshore gas gathering lines are currently unregulated if located in Class 1 locations or Type B in certain Class 2 locations (that is, those locations not meeting the alternative criteria of 49 CFR 192.8(b)(2)). Since PHMSA doesn't collect data on unregulated gas gathering lines, for this analysis, PHMSA relied on comments and data submitted by API[40] to estimate the population of unregulated onshore gas gathering pipelines. API's submittal indicates that an estimated 241,000 miles of currently unregulated onshore gas gathering lines exist within 45 operators' asset portfolios. Those operators also provided information regarding the amount of steel and cathodically protected pipelines. PHMSA estimated that the API estimate represents 70% of total unregulated mileage. Thus, PHMSA estimated that there are a total of 344,086 miles of unregulated gas gathering pipeline infrastructure, 68,749 of which will be newly regulated as Type A, Area 2 (**Table 3-88**).

[40] Letter from Amy Emmert, Policy Advisor, Upstream and Industry Operations, American Petroleum Institute, Re: Pipeline Safety: Safety of Gas Transmission Pipelines (Docket No. PHMSA-2011-0023), October 23, 2012.

Table 3-88. Estimation of Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines

Type (Class 1 and Class 2)	2012 API Member Estimate[1]	Estimated Unregulated Mileage[2]	Difference[3]
Type A, Area 2 (high stress, ≥ 8")	48,124	68,749	20,625
High stress, < 8"	70,921	101,316	30,395
Type A (assumed < 8")[4]	13,542	19,346	5,804
Low stress, all sizes	108,273	154,676	46,403
Total	**240,860**	**344,086**	**103,226**

1. Source: Letter from Amy Emmert, Policy Advisor, Upstream and Industry Operations, American Petroleum Institute, Re: Pipeline Safety: Safety of Gas Transmission Pipelines (Docket No. PHMSA-2011-0023), October 23, 2012. Data from 45 operators.
2. Calculated as API estimate divided by 0.7, based on PHMSA best professional judgment. Type A Area 2 lines would be newly regulated.
3. Calculated as total mileage minus group 1 operator mileage.
4. PHMSA assumed that any mileage reported as unknown diameter in the API comments is less than 8" in diameter because operators would be aware of their larger high-pressure lines.

Of the Type A, Area 2 mileage that will become regulated, PHMSA assumed that most (97%) is attributable to operators of currently regulated lines, as shown in **Table 3-89**.

Table 3-89. Estimation of Newly Regulated Mileage by Operator Group

Operator Type	Percent of Total Mileage[1]	Newly Regulated Type A Area 2 Miles	All other Unregulated Miles
No existing regulated lines (group 1)	3%	2,200	8,811
Existing regulated lines (group 2)	97%	66,549	266,526
Total	**100%**	**68,749**	**275,337**

1. Source: PHMSA best professional judgment

3.8.2.4.3 Estimation of Costs

This section details the estimation of the different incremental costs.

Corrosion Control

The API comments indicate that 95% of currently unregulated steel Type A, Class 1 gathering lines have cathodic protection. Based on the larger diameters and higher operating pressures that define Type A, Area 2 pipelines, PHMSA assumed that 100% of the newly-regulated Type A, Area 2 gathering lines are made of steel, and 95% have cathodic protection. **Table 3-90** shows the resulting estimates of mileage needing corrosion control, and the total one-time costs.

Table 3-90. Estimation of One-Time Costs for Corrosion Control for Newly Regulated Gas Gathering Lines

Operator Type	Newly Regulated Mileage	Mileage without Cathodic Protection[1]	One-Time Corrosion Control Unit Cost per Mile[2]	Total One-Time Corrosion Control Cost
Group 1	2,200	110	$17,183	$1,890,120
Group 2	66,549	3,327	$12,887	$42,882,100

Table 3-90. Estimation of One-Time Costs for Corrosion Control for Newly Regulated Gas Gathering Lines				
Operator Type	**Newly Regulated Mileage**	**Mileage without Cathodic Protection[1]**	**One-Time Corrosion Control Unit Cost per Mile[2]**	**Total One-Time Corrosion Control Cost**
Total	**68,749**	**3,437**	**NA**	**$44,772,220**
1. Calculated as 0.5% of newly regulated mileage. 2. Source: see Table 3-86				

Surveillance

Table 3-91 shows the estimation of periodic costs for right-of-way population surveys (surveillance), on an annualized basis.

Table 3-91. Estimation of Total Costs for Right-of-Way Surveillance for Newly Regulated Gas Gathering Lines				
Operator Type	**Newly Regulated Mileage**	**Periodic Right-Of-Way Surveillance Unit Cost[1]**	**Periodic Surveillance Costs (every 3 years)[2]**	**Annualized Surveillance Cost[3]**
Group 1	2,200	$118	$258,655	$86,218
Group 2	66,549	$29	$1,956,077	$652,062
Total	**68,749**	**NA**	**$2,214,732**	**$738,244**
1. Source: see Table 3-86 2. Unit costs times mileage. 3. Periodic costs divided by three.				

Recurring Costs

Table 3-92 shows the calculation of recurring (annual) costs for corrosion control, line markers, damage prevention, public awareness, and emergency plans.

Table 3-92. Estimation of Recurring Costs for Newly Regulated Gas Gathering Lines							
Mileage Type	**Mileage**	**Unit Costs[2]**					**Total Annual Cost[1]**
		Corrosion Control	**Line Markers**	**Damage Prev.**	**Public Awareness**	**Emergency Plan**	
Operator Group 1							
Total	2,200	$0	$153	$0	$198	$325	$1,485,777
Steel lines; cathodic protection	2,090	$22	$0	$0	$0	$0	$46,933
Steel lines; no cathodic protection	110	$449	$0	$0	$0	$0	$49,403
Operator Group 2							
Total	66,549	$0	$76	$29	$20	$20	$9,669,209
Steel lines; cathodic	63,221	$22	$0	$0	$0	$0	$1,419,721

Table 3-92. Estimation of Recurring Costs for Newly Regulated Gas Gathering Lines							
Mileage Type	Mileage	Unit Costs[2]					Total Annual Cost[1]
		Corrosion Control	Line Markers	Damage Prev.	Public Awareness	Emergency Plan	
protection							
Steel lines; no cathodic protection	3,327	$337	$0	$0	$0	$0	$1,120,832
Total	**68,749**	**NA**	**NA**	**NA**	**NA**	**NA**	**$13,791,875**
1. Calculated as mileage times the sum of applicable unit costs. 2. See Table 3-86							

3.8.2.4.4 Total Incremental Compliance Costs for Safety Provisions

Table 3-93 summarizes the present value of one time, periodic, and recurring (annual) costs at seven and three percent discount rates.

Table 3-93. Present Value of Compliance Costs, Gas Gathering Safety Provisions[1]				
Component	Total (7%)	Average Annual (7%)	Total (3%)	Average Annual (3%)
One-time	$44,772,220	$2,984,815	$44,772,220	$2,984,815
Annualized periodic	$7,194,533	$479,636	$9,077,502	$605,167
Annual	$134,408,273	$8,960,552	$169,585,900	$11,305,727
Total	**$186,375,026**	**$12,425,002**	**$223,435,622**	**$14,895,708**
1. Total is present value over 15 year study period; average annual is total divided by 15.				

3.8.3 REPEAL THE REPORTING EXEMPTIONS FOR GAS GATHERING LINES

This section addresses the repeal of reporting exemptions for gas gathering lines.

3.8.3.1 Problem Statement

Operators of unregulated onshore gas gathering pipelines are currently exempt from immediate notice and reporting of incidents, reporting of Safety-Related Conditions (SRCs), submittal of annual pipeline summary data, and reporting into PHMSA's National Registry of Pipeline Operators. Two additional types of gas gathering pipelines (gravity lines and lines within the inlets of the Gulf of Mexico) are also exempt from these reporting requirements. PHMSA determined that information about these gathering lines is needed to fulfill PHMSA's statutory and oversight obligations and to evaluate pipeline safety to determine if additional oversight is warranted. The proposed rule would repeal exemptions of previously unregulated gas gathering pipelines to comply with the reporting requirements in 49 CFR Part 191. Collecting this data would allow PHMSA to more fully understand and better assess the safety and environmental risks associated with these pipelines.[41] [42]

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[41] Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety, GAO-12-388, March 2012.
[42] Department of Transportation is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to

3.8.3.2 Assessment of Regulatory Impact

Reports required in the proposed rule are listed in **Table 3-94**.

Table 3-94. Gas Gathering Pipeline Reporting Requirements

Regulation	Description	Timing
191.5	Immediate notice of certain incidents	Upon event
191.15	Incident report	Upon event
191.17	Annual report (i.e., pipeline summary data)	Annually
191.22(a)	Operation identification request	Once
191.22(c)	Notification of changes	Upon event
191.23	Safety-related condition report	Upon event

Validation of operator identification (OPID) numbers through the National Registry of Pipeline Operators [(§ 191.22(b)] and filing of offshore pipeline condition reports (§ 191.27) are expired requirements and would not be applicable to newly-regulated gathering lines. However, the other reporting requirements under 49 CFR Part 191 applicable to gas transmission pipelines would selectively apply, as described below.

PHMSA estimated that a total of approximately 344,000 miles of gathering lines would be subject to either some or all of the reporting requirements of § 191.5, § 191.15, § 191.17, § 191.22(a) and (c), and § 191.23, including the accompanying administrative provisions of Part 191. The new Type A, Area 2 lines subject to selected safety provisions of PHMSA's regulations would be subject to all of the reporting provisions. The remaining gathering lines not subject to Part 192 would be subject to a set of selected reporting provisions as shown in **Table 3-95**.

Table 3-95. Proposed Reporting Requirements

Regulation	Description	Type A, Area 2 Lines	All Other Currently Unregulated Lines
191.5	Immediate Notice of certain incidents	√	√
191.15	Incident Reports	√	√
191.17	Annual Reports (i.e., pipeline summary data)	√	√
191.22(a)	OPID Request	√	√
191.22(c)	Notification of Changes	√	NA
191.23	Safety-Related Condition Reports	√	NA
NA = not applicable			

Operators of currently regulated lines already have the processes, procedures, forms, and training to readily accommodate reporting. However, the actual reporting would result in additional costs. Newly-regulated operators under 49 CFR Part 191 would require new procedures and processes to comply, incurring costs.

3.8.3.3 Analysis Assumptions

Reporting requirements are annual, one-time, or event-driven. Filing an annual report would be a new requirement for operators with no previously regulated gas pipelines, but not for

Improve Pipeline Safety, GAO-14-667, August 2014

operators of existing pipelines regulated under Part 192 (although their reported numbers would need to be revised due to the additional gathering line mileage that would be reported).

For the National Registry reporting, all newly-regulated operators would need to file a one-time OPID Request. Operators with existing regulated lines already have OPIDs assigned, and the proposed rule includes a notification of change exemption for those gaining 50 miles or more of newly-regulated lines to report as a result of the proposed rule.

3.8.3.4 Estimation of Costs

This section develops estimates of cost by provision.

3.8.3.4.1 Type A, Area 2 and All Other Currently Unregulated Onshore Gathering Lines

Newly-regulated operators (group 1) would incur incremental compliance costs to create new procedures, processes, and guidance for each of the newly required reports. Operators with existing regulated lines (group 2) would only need to expand existing reporting mechanisms at less cost. For both groups of operators, there would be additional compliance costs associated with the actual submission of the reports, either on an annual or on a per-event basis. Estimated unit costs to file reports on a per-operator, per-year, or per-event basis for the various reporting provisions of the proposed rule are summarized in **Table 3-96**. PHMSA estimated these costs by estimating the amount of time involved for each task associated with the individual reporting item multiplied by typical hourly rates for the various types of operator staff positions involved.

Table 3-96. Estimates of Unit Cost for Reporting Provisions (Per report)

Component	Group 1 One-Time	Group 1 Per Event	Group 2 One-Time	Group 2 Per Event	Group 1,2 Annual
Immediate notice	$1,300	$100	$100	$100	NA
Incident report	$2,580	$1,400	$180	$1,400	NA
SRC report	$2,900	$340	$180	$340	NA
Annual report	$1,780	NA	$620	NA	$280
OPID request	$520	NA	NA	NA	NA
Notification of change	$980	$85	$180	$85	NA

Source: PHMSA best professional judgment
Group 1 = operators without pre-existing lines.
Group 2 = operators with pre-existing regulated lines.
See Table 3-98 for reporting requirements applicable to Group 1 and Group 2 mileage

3.8.3.4.2 Gravity Lines and Lines within the Inlets of the Gulf of Mexico

The proposed rule would repeal the reporting exemption for gravity lines and lines within the inlets of the Gulf of Mexico. These types of gathering lines are rare, and total mileage is insignificant compared to the very large amount of onshore gathering line mileage. Also, it is very likely that most such lines exist within the asset portfolios of operators of onshore gathering lines accounted for in this analysis. As a result, the cost to implement these four reporting provisions for these lines is negligible.

3.8.3.4.3 Summary of Operators and Mileages Impacted by the Reporting Provisions

Based on the analysis of mileages by operator group included in Section 3.8.2, the operator groups and the mileages to which the various reporting provisions apply are summarized in **Table 3-97** and **Table 3-98**.

Table 3-97. Summary of Mileages by Operator Group

Type A, Area 2 Lines		All Other Currently Unregulated Lines[1]	
Group 1	Group 2	Group 1	Group 2
2,200	66,549	8,811	266,526

Group 1 = operators without existing regulated lines.
Group 2 = operators of existing regulated lines.
1. Total estimated currently unregulated mileage minus Type A, Area 2 currently estimated unregulated.

Table 3-98. Reporting Requirements by Operator Group

Regulation	Description	Type A, Area 2 Lines		All Other Currently Unregulated Lines		Timing
		Group 1	Group 2	Group 1	Group 2	
191.5	Immediate notice	√	√	√	√	Upon event
191.15	Incident report	√	√	√	√	Upon event
191.17	Annual report	√	√	√	√	Annually
191.22(a)	OPID request	√	√	√	√	Once
191.22(c)	Notification of changes	√	√	NA	NA	Upon event
191.23	Safety-related condition report	√	√	NA	NA	Upon event

Group 1 = operators without existing regulated lines
Group 2 = operators of existing regulated lines
NA = not applicable

3.8.3.4.4 One-time Compliance Costs for Reporting Provisions

All Type A, Area 2 gathering lines and other currently unregulated gathering lines would incur one-time compliance costs for reporting. One-time costs would be greater for operators in group 1 who currently are not regulated under Part 191. The numbers of operators with and without pre-existing regulated lines were estimated for each operator group, since the reporting requirements differ.

Operators in group 2 are already subject to Part 191 reporting requirements. PHMSA assumes that each of these 292 operators (as established in section 3.8.B) would incur some level of one-time compliance costs. PHMSA assumes that the 45 large operators that contributed to API's submittal would incur the larger one-time costs associated with all reporting provisions. Because many of the remaining 247 operators are large or medium size operators, PHMSA assumes that 90% of them (222) would also be subject to all reporting provisions. PHMSA assumes the remaining operators (25) would be subject to fewer reporting provisions.

The operators in group 1 are assumed to have only a small amount of reported mileage, consistent with the assumption made in Section 3.8.2. Therefore, it is likely that many of them do not operate lines Type A, Area 2 lines. For purposes of this analysis, PHMSA assumes that all reporting provisions would apply to half (38) of the operators in group 1,

and fewer reporting provisions would apply to the other 38 operators.

Applying the unit cost estimates to the numbers of operators, the total one-time compliance costs are shown in **Table 3-99**.

Table 3-99: One Time Compliance Costs of Gathering Line Reporting Requirements

Category	Miles	Cost per Mile	Total One-Time Costs
Type A, Area 2 Lines[1]			
Group 1	2,200	$173.77	$382,280
Group 2	66,549	$5.06	$336,420
Subtotal	68,749	NA	$718,700
All Other Currently Unregulated Lines[2]			
Group 1	8,811	$26.65	$234,840
Group 2	266,526	$0.08	$22,500
Subtotals	275,337	NA	$257,340
Total	**344,086**	**NA**	**$976,040**

Source: PHMSA best professional judgment
Group 1 = operators without existing regulated lines
Group 2 = operators of existing regulated lines
1. Immediate notice, incident, SRC, annual, OPID request, notification of change reporting.
2. Immediate notice, incident, annual, and OPID request reporting.

3.8.3.4.5 Recurring Compliance Costs for Reporting Provisions

Annual reports would be required for each operator. The first-year costs would be significantly higher since in subsequent years operators would only report mileage that has changed and/or been added. Higher first-year costs for annual reporting are accounted for in the one-time costs estimated in Section 3.8.3.4.4 above. This section addresses only the annual recurring costs.

Immediate notice, incident reporting, and SRC reporting costs are driven by events. To estimate these recurring reporting costs, PHMSA estimated the number of triggering events.

<u>Incidents Reporting</u>
PHMSA estimated the number of reportable incidents for which incident reporting would be required, based on a predicted incident rate established in Section 6.2.3. For Type A, Area 2 lines subject to Part 192, PHMSA expects the incident rate to decrease over time due to the influence of implementing the applicable safety regulations. The other currently unregulated gathering lines would not be subject to Part 192 so PHMSA assumed that the baseline incident rate would remain constant. PHMSA estimated the costs for immediate notice and incident reports using these incident rates. **Table 3-100** summarizes the results.

Table 3-100. Cost of Incident Reporting for Newly Regulated Gas Gathering Pipelines

Year	Incidents per 1,000 Miles[1]	Cost per Incident[2]	Annual Cost per 1,000 Miles	Costs per Year[3]
1	0.2	$1,500	$300	$20,625
2-5	0.1	$1,500	$150	$10,312
6-15	0.04	$1,500	$60	$4,125

Table 3-100. Cost of Incident Reporting for Newly Regulated Gas Gathering Pipelines				
Year	Incidents per 1,000 Miles[1]	Cost per Incident[2]	Annual Cost per 1,000 Miles	Costs per Year[3]
1. Source: PHMSA best professional judgment. See benefits analysis.				
2. Table 3-86, $1,400 for incident report, $100 for immediate notification per incident				
3. Cost per 1,000 miles × 68.749 thousand Type A Area 2 miles.				

SRC Reporting

SRC reporting is only required for operators of Type A, Area 2 gathering lines. Historically, SRC reports are filed infrequently, particularly for the relatively small amount of gathering mileage currently regulated. Based on historical reporting levels, PHMSA estimated approximately 0.23 SRC reports each year per 1,000 miles of gathering lines. PHMSA assumed this rate would remain relatively constant. **Table 3-101** show the calculation of annual compliance costs for reporting SRCs.

Table 3-101. Annual Costs for Safety Related Condition Reports			
Reports per 1000 Miles[1]	Unit Cost per Report[2]	Cost per 1000 Miles[3]	Total Annual Costs[4]
0.23	$340	$78.20	$5,376
1. Source: Estimated based on historical reporting levels			
2. Source: PHMSA best professional judgment			
3. Calculated as reports times unit cost.			
4. Calculated as cost per 1000 miles times thousands of Type A Area 2 miles (Table 3-96).			

Annual Reporting

All operators would be required to report annually, and reporting costs are estimated to be the same for all operators. Operator numbers established in Section 3.8.C.4.4 are used to estimate annual recurring costs. Since these lines are all exempt from 49 CFR Part 192, Subpart O Integrity Management Program (IMP) requirements, portions of the annual report associated with IM program data would not be required by any of these operators for their gathering lines (newly-regulated or not). **Table 3-102** shows the costs for filing annual reports.

Table 3-102. Costs for Annual Reporting			
Group	Miles	Annual Cost Per 1000 Miles	Total Annual Costs
Type A Area 2	68,749	$1,242	$85,400
All other regulated	275,337	$64	$17,640
Total	**344,086**	**NA**	**103,040**

National Registry Reporting

Operators of existing regulated gathering lines already have OPID numbers. Therefore, only operators with no regulated lines incur costs for requesting an OPID. OPIDs remain in the National Registry until the operator requests a retirement. Therefore, costs are included in the one-time compliance costs covered in Section 3.8.C.4.4, for newly-regulated operators (i.e., operator group 1).

The notification of change provision of the National Registry drives incremental compliance costs for reporting and would only apply to operators of Type A, Area 2 lines. Operators are required to report whenever an operator experiences one of the eight changes specifically defined in § 191.22(c).

Because notification of change is a relatively new regulation, very little historical data exists. However, this particular sector of the pipeline industry is undergoing a disproportionate amount of change, particularly with new construction, and it is likely that some amount of reporting would occur. The primary changes particularly applicable are: new pipeline construction of 10 miles or more; acquisition or divestiture of 50 miles or more of pipelines; and, a change in the entity operating the pipelines or administering a regulated safety program. For illustration, PHMSA assumed that 30% (92) of the 305 operators of Type A, Area 2 lines would construct 10 or more miles of gathering line each year and that 10% (30) have a reportable acquisition, divestiture, merger, or operating entity change each year. Accordingly, **Table 3-103** shows the total annually recurring compliance costs estimated for change reporting.

Table 3-103. Recurring Incremental Compliance Costs for National Registry Reporting

Operator Group	Number of Operators[1]	Annual Costs per Operator[1]	Total Annual Costs
Constructing 10 or more miles of pipelines	92	$85	$7,820
Acquisition, divestiture, merger, and entity changes	31	$85	$2,635
Total	**123**	**$85**	**$10,455**
1. Source: PHMSA best professional judgment			

3.8.3.4.6 Total Incremental Compliance Costs for Reporting Provisions

Applying the costs from sections 3.8.3.4.4 through 3.8.3.4.5 to the 15-year study period yields a total incremental cost of compliance for the reporting provisions of Topic Area 8. **Table 3-104** and **Table 3-105** show the present value results.

Table 3-104. Present Value of Recurring Reporting Costs

Provision	7% Discount Rate		3% Discount Rate	
	Total[1]	Average Annual[2]	Total[1]	Average Annual[2]
Incident reporting	$77,657	$5,177	$90,219	$6,015
SRC reporting	$52,393	$3,493	$66,105	$4,407
Annual reporting	$842,180	$56,145	$1,130,046	$75,336
National Registry Reporting	$101,889	$6,793	$128,555	$8,570
Total	**$1,074,119**	**$71,608**	**$1,414,926**	**$94,328**
1. Represents 15-year study period. 2. Total divided by 15.				

Table 3-105. Present Value of Reporting Provision Costs

Type of Provision	7% Discount Rate		3% Discount Rate	
	Total	Average Annual	Total	Average Annual
Recurring[1]	$1,074,119	$71,608	$1,414,926	$94,328
One-time[2]	$976,040	$65,069	$976,040	$65,069
Total	**$2,050,159**	**$136,677**	**$2,390,966**	**$159,398**
1. Source: See Table 3-83. 2. Source: See Table 3-75.				

3.9 SUMMARY OF COSTS

Table 3-106 summarizes the estimated present value of compliance costs by Topic Area. PHMSA also estimated the climate-related costs associated with the methane releases associated with compliance. **Table 3-107** shows the combined results. **Table 3-108** shows a breakout of compliance costs by subtopic are for Topic Area 1.

Table 3-106. Summary of Present Value Compliance Costs (Millions 2015$)[1]

Topic Area	7% Discount Rate		3% Discount Rate	
	Total	Average Annual	Total	Average Annual
1	$267.3	$17.8	$330.1	$22.0
2	$32.7	$2.2	$19.4	$1.3
3	$10.0	$0.7	$12.4	$0.8
4	$94.8	$6.3	$118.5	$7.9
5	$1.1	$0.1	$1.1	$0.1
6[2]	$2.9	$0.2	$2.9	$0.2
7	$0.4	$0.0	$0.4	$0.02
8	$188.4	$12.6	$225.8	$15.1
Total	**$597.5**	**$39.**8	**$710.5**	**$47.**4

1. Total present value over 15 study period; average annual calculated by dividing total by 15.
2. PHMSA analyzed this component with a pre-statutory baseline, however most operators are expected to be in compliance with the Act

Table 3-107. Summary of Present Value Total Costs (Millions 2015$)[1]

Component	7% Discount Rate		3% Discount Rate	
	Total	Average Annual	Total	Average Annual
Compliance costs	$570.0	$38.0	$683.1	$45.5
Social cost of methane[2]	$27.5	$1.8	$27.5	$1.8
Total	**$597.5**	**$39.8**	**$710.5**	**$47.4**

1. Total present value over 15 study period; average annual calculated by dividing total by 15.
2. Based on 3% value. See Appendix B for discussion of other estimated values.

Table 3-108. Breakdown of Present Value Costs, Topic Area 1 (Millions 2015$)

Subtopic Area	7% Discount Rate		3% Discount Rate	
	Average Annual	Total	Average Annual	Total
Re-establish MAOP: HCA > 30% SMYS	$0.5	$7.4	$0.60	$9.0
Re-establish MAOP: Inadequate Records	$8.0	$120.3	$9.8	$147.2
Integrity Assessment: Non-HCA	$6.3	$94.9	$7.9	$119.2
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	$3.0	$44.7	$3.6	$54.7
Total	**$17.8**	**$267.3**	**$22.0**	**$330.1**

HCA = high consequence area
MAOP = maximum allowable operating pressure
SMYS = specific minimum yield strength

4. ANALYSIS OF BENEFITS

This section provides detailed analysis of benefits by topic area. PHMSA estimated the value of avoiding fatalities, injuries, property damage, and environmental damage associated with pipeline incidents preventable through the proposed regulatory requirements.

4.1 TOPIC AREA 1: RE-ESTABLISH MAOP, VERIFICATION OF MATERIAL PROPERTIES, AND INTEGRITY ASSESSMENT AND REMEDIATION FOR SEGMENTS OUTSIDE HCAS

The primary quantifiable benefit of the proposed requirements is the potential number of pipeline incidents that may be averted by conducting integrity assessments and repairs on pipeline segments located outside of HCAs that have not been previously assessed or that are assessed as part of re-establishing MAOP. Therefore, the benefits are based on the identification of defects from integrity assessments and leaks and failures during pressure testing assessments. Both conditions would require prompt repair prior to returning the line to service (or be addressed via other measures such as near-term pressure reductions).

4.1.1 ANALYSIS ASSUMPTIONS

PHMSA quantified and monetized the benefit of avoiding incidents assuming that defects or pressure test failures represent imminent or near-term integrity threats that could lead to future reportable pipeline incidents and associated costs, When monetizing the benefit, PHMSA assumed that the benefit is realized during the same year as the assessment is conducted.

In the case of pressure test failures, the defect must be repaired before the test can be successfully concluded. In the case of immediate conditions, the repair must be made immediately (typically within five days) or else the operating pressure must be reduced (in order to preclude failure) until the defect can be repaired. For non-immediate conditions, the proposed rule would require an operator to evaluate the defect and reduce pressure if an immediate hazard is present, and complete repairs as soon as feasible. Therefore, since the risks of an incident have generally been eliminated at the time of detection, PHMSA assumed that benefits from avoided incidents accrue in the year of detection.

PHMSA does not have specific data with which to quantify the percent of defects which would have resulted in failure and thus the safety benefits. PHMSA used its professional judgment to estimate this percentage by method of discovery (assessment method).

4.1.2 ANALYTICAL APPROACH

PHMSA quantified and monetized benefits using the following equation:

Miles Assessed x Incidents Averted Rate x Average Incident Consequences

Section 3.1 provides the mileage estimates for each sub-topic area in. Further, the mileage estimates are broken down by class location and by type of assessment. The sections below describe the estimation of incidents averted and consequences.

In addition, PHMSA estimated cost-savings as described in Section 4.2.2.3.

4.1.2.1 Incidents Averted Rate

PHMSA estimated the rate of incidents averted by estimating and multiplying the defect discovery rate per mile by test method by the percent of defects that would have resulted in an incident in the absence of the rule (i.e., not detected and repaired). PHMSA used data from the hazardous liquid and gas transmission annual reports shown in Appendix C in estimating defect discovery rates. **Table 4-1** shows the assumed rates for different categories of pipe affected under Topic Area 1.

Table 4-1. Summary of Estimated Defect Discovery Rates (per Mile)

Requirement	Defect Discovery Rate	Description
Integrity verification, previously assessed pipe (HCA)[1]	ILI, DA: 0.05 (immediate); 0.38 (scheduled) PT: 0.03	Represents difference between hazardous liquid and gas transmission discovery rates (see Appendix C) since proposed gas transmission requirements resemble existing requirements for hazardous liquid pipe.
Non-HCA integrity verification and MCA assessments of previously unassessed pipe[2]	ILI, DA: 0.10 (immediate); 0.49 (scheduled) PT: 0.03	Represents hazardous liquid baseline discovery rate since proposed repair criteria and assessment requirements are similar.

1. Re-establishing MAOP for previously untested pipe and pipe for which records are inadequate.
2. Includes requirements addressing previously untested pipe, inadequate records, and integrity assessments outside of HCAs.

Table 4-2 provides PHMSA's estimates of defects discovered that would have resulted in failure (operator would not have identified and repaired) based on considerations regarding these discoveries. For example, immediate repair criteria represent a calculated failure pressure less than 1.1 times operating pressure or pipe wall loss greater than 80% loss. Other factors to consider are overpressure protection set at 1.04 times MAOP; a safety factor of 6% or less to account for combined stresses; and that the operator has 180 days for ILI result evaluation prior to the ILI results being an immediate discovery. Therefore, based upon a safety margin of less than 6%, a failure rate between 3% and 12.5% is reasonable. Pressure tests are very effective at finding defects (wall loss, dents, or cracking) that would not otherwise have been abated. PHMSA invites comments on these estimates.

Table 4-2. Estimated Percent of Defects Which Would Have Resulted In Failure

Method	Low	High
Inline and direct assessment (immediate repair)	3.0%	12.5%
Inline and direct assessment (scheduled repair)	0.3%	0.5%
Pressure test	33.3%	50.0%

Source: PHMSA best professional judgment considering that immediate repair criteria represent a calculated failure pressure less than 1.1 times operating pressure or pipe wall lost greater than 80% loss, and other factors including overpressure protection, safety margin for combined stresses, and 180 days for results to represent immediate discovery. Pressure tests are very effective at finding defects (wall loss, dents, or cracking) that would not otherwise have been abated.

Multiplying the mileage assessed via each method (see Section 3.1) by the defect discovery rate and percent that would have resulted in failure results in the estimates of incidents averted shown in **Table 4-3**.

Table 4-3. Estimated Incidents Averted, Topic Area 1								
Scope	**Mileage**		**HCA %**		**Incidents Averted[1]**			
	ILI and DA	**PT**	**HCA**	**Non-HCA**	**ILI and DA, Immediate**	**ILI and DA, Scheduled**	**PT**	**Total**
HCA >30% SYMS	793	116	100%	0%	1.2-4.9	0.9-1.5	1.3-2	3.4-8.4
HCA; Class 3 and 4 non-HCA	3,686	678	42%	58%	8.9-37.2	4.9-8.1	7.8-11.8	21.6-57.1
MCA Class 3 and 4; MCA Class 1 and 2 (piggable)	7,129	250	0%	100%	22.1-92.2	10.4-17.3	2.9-4.4	35.4-113.9
HCA 20-30% SMYS; non-HCA Class 3 and 4; MCA Class 1 and 2 (piggable)	2,647	170	9%	91%	7.8-32.6	3.8-6.3	2-3	13.5-41.8
Total	**14,255**	**1,213**	**NA**	**NA**	**40.1-166.9**	**19.9-33.2**	**14.0-21.2**	**74.0-221.3**

DA = direct assessment
HCA = high consequence area
ILI = inline inspection
MCA = moderate consequence area
PT = pressure test
SMYS = specified minimum yield strength
1. Based on multiplying estimated mileage by defect discovery rate and range of percentage of defects that would have resulted in failure absent the proposed rule.

4.1.2.2 Average Incident Consequences

Operators identify the cause attributable to an incident on incident reports submitted to PHMSA. Some incidents might not be averted by integrity assessments and the management of time-dependent threats. Incidents due to hurricanes or other extreme weather events, or third-party damage, in which the pipe fails at the time of the event would not necessarily be averted by the requirements in the proposed rule under Topic Area 1. **Table 4-4** summarizes causes preventable by integrity assessments; Appendix E summarizes the subset of gas transmission incidents attributable to these causes. (Note that the list of causes was revised in 2010.) PHMSA significantly expanded the information required in incident reporting in 2010. For some of the topic areas PHMSA used only incident data since 2010; prior to 2010 specific information is not available that would support an effective analysis of those topic areas.

Table 4-4. Causes of Incidents Detectable by Modern Integrity Assessment Methods	
2003-2009	**2010-present**
External corrosion	External corrosion
Internal corrosion	Internal corrosion
Rupture of previously damaged pipe	Previous damage due to excavation activity
Body of pipe; pipe seam weld	Original manufacturing-related (not girth weld or other welds formed in the field)
Joint; butt weld; fillet weld	Construction-, installation-, or fabrication-related
NA	Environmental cracking-related
Source: PHMSA Incident Report Form	

The data summarized in Table E-2 was reported to PHMSA in operator incident reports; except that publicly available information was used to estimate the consequences of the 2010 San Bruno incident (see Appendix D). The specific incident data is also provided in Appendix E. For comparison, incident data for gas transmission incidents for all causes is summarized (Table E-1). However, the subareas within Topic Area 1 analyze requirements that are focused on selected locations, such as HCAs, MCAs, or Class 3 or 4 locations. PHMSA filtered the data to estimate benefits for each subarea as follows:

Table 4-5 summarizes the average incident consequences for these groups of incidents.

Table 4-5. Estimated Average Per Incident Consequences, Topic Area 1 (2015$)

Subtopic Area	HCA	Non-HCA
MAOP verification for segments within HCA	$23,408,790[1]	NA
MAOP verification for segments with inadequate records within HCA and Class 3 and Class 4	$23,408,790[1]	147,800[2]
Integrity assessments for segments within MCA in Class 3 and Class 4, and Class 1 and Class (piggable)	N/A[1]	$1,085,660[3]
MAOP verification for segments within HCA (operating between 20%-30% SMYS) and MCA (Class 3 and Class 4; Class 1 and Class 2 piggable)	$23,408,790[1]	$1,085,660[3]

Source: PHMSA Gas Transmission Incident Reports summarized in Tables E-3 through E-6.
HCA = high consequence area
MCA = moderate consequence area
MAOP = maximum allowable operating pressure
NA = not applicable
PT = pressure test
SMYS = specified minimum yield strength
1. Based on HCA incidents from 2003-2015 (see Table E-3).
2. Based on Class 3 and 4 non-HCA incidents from 2003-2015 (see Table E-8).
3. Based on estimate of incidents that may represent MCA incidents (see Table E-4).

There are several economic consequences of pipeline incidents that are not covered in PHMSA's data, and hence are not included in this benefit-cost analysis. In particular, even minor pipeline incidents cause an interruption of service that may last a few days or may occasionally (as in the case of San Bruno) be permanent. There is a private cost to the pipeline operator in the form of lost tolls, a loss to shippers in the form of deferred shipment, storage, or lost or deferred gas production, and potentially a loss to end users in the form of having to make unplanned alternative supply arrangements for some period of time. These costs are incident-, time- and location-specific, and spread across multiple actors, and are difficult to estimate.

In addition, pipeline incidents may generate emergency response and other social costs borne by local communities and that are not captured in operator's cost estimates filed with the incident report. Except in the case of San Bruno, emergency response costs have not been included in the consequences of incidents.

Historical data establish that incidents are often relatively low in cost, but that occasional high cost incidents have occurred and that infrequent, extremely high cost incidents have also occurred. High consequence incidents have also occurred across Class locations; the second most consequential incident since PHMSA has been keeping records (Carlsbad, New

Mexico, in 2000) occurred in a Class 1 location.[43] This incident resulted in the death of 12 people camping under a concrete-decked steel bridge that supported the pipeline across the river and an estimated $1 million in property and other damages.

4.1.2.3 Cost Savings

With respect to the statutory requirement in the Act, 23, Congress required DOT to require that pipeline operators conduct a records verification to ensure that the records accurately reflect the physical and operational characteristics of the pipelines and confirm the established MAOP. The results of that action indicated that problems similar to those that contributed to the San Bruno incidents are more widespread than previously believed. As a result, the proposed rule would establish consistent standards by which operators would correct these issues in a way that is more cost effective than the current regulations would require (which could require more extensive destructive testing, pressure testing, and/or pipe replacement).

PHMSA estimated the cost savings to operators associated with the Section 23(c) mileage. Existing regulatory requirements [§192.107(b)] related to bad or missing records would be more costly for operators to achieve compliance. Currently, in order to maintain operating pressure, operators must excavate the pipeline at every 10 lengths of pipe (commonly referred to as joints) in accordance with section II-D of Appendix B of Part 192 (as specified in §192.107(b)), do a cutout, determine material properties by destructive tensile test, and repair the pipe. The process is similar to doing a repair via pipe replacement. PHMSA developed an average for performing such a cutout material verification ($75,000) by reviewing typical costs to repair a small segment of pipe by pipe replacement. The estimate accounts for various pipe diameters and regional cost variance. PHMSA assumed each joint is 40 feet long; ten joints are 400 ft. The number of cutouts required by existing rules is therefore the miles subject to this requirement multiplied by 5,280/400 (13.2). Therefore, the average cost to comply with these requirements is approximately $990,000 per mile.

The proposed rule would allow operators to perform a sampling program that opportunistically takes advantage of repairs and replacement projects to verify material properties at the same time. Over time, operators will collect enough information gain significant confidence in the material properties of pipe subject to this requirement. The proposed rule nominally targets conducting an average of one material documentation process per mile. In addition, operators would be allowed to perform nondestructive examinations, in lieu of cutouts and destructive testing, when the technology provides a demonstrable level of confidence in the result.

Table 4-6 provides a summary of the cost savings.

Table 4-6. Estimation of Average Annual Cost Savings of Proposed Material Documentation Requirements[1]

Component	Average Annual Cost (Millions 2015$)
Existing requirements (cutouts) [2]	$288.0
Proposed rule (IVP)[3]	$14.3
Cost savings (over 15 years)	$273.7

[43] NTSB/PAR-03/01- http://www.ntsb.gov/investigations/AccidentReports/Reports/PAR0301.pdf

Table 4-6. Estimation of Average Annual Cost Savings of Proposed Material Documentation Requirements[1]	
Component	**Average Annual Cost (Millions 2015$)**

IVP = integrity verification program
NA = not applicable
1. Based on 291 miles of pipe for which there are incomplete, missing, or inadequate records to substantiate maximum allowable operating pressure as indicated in the 2014 Gas Transmission Annual Report. The proposed requirements would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods.
2. Calculated as mileage multiplied by 13.2 cutouts per mile and $75,000 per cutout.
3. Average annual cost to re-establish MAOP for segments with inadequate MAOP records using methods permitted in the proposed rule (see Section 3.1.5).

4.1.3 ESTIMATION OF BENEFITS

Table 4-7 shows the estimated safety benefits estimates for each sub-topic area. **Table 4-8** shows the estimated cost savings.

Table 4-7. Present Value of Safety Benefits, Topic Area 1 (Millions $2015)

	7% Discount Rate		3% Discount Rate	
Component	**Total[1]**	**Average Annual[2]**	**Total[1]**	**Average Annual[2]**
MAOP verification for segments within HCA	$52-$128	$3-$9	$66-$162	$4-$11
MAOP verification for segments with inadequate records within HCA + Class 3 & 4	$140-$371	$9-$25	$177-$468	$12-$31
Integrity assessments for segments within MCA in Class 3&4 and Class 1&2 (piggable)	$25-$80	$2-$5	$32-$101	$2-$7
MAOP verification for segments within HCA(20%-30% SMYS) + MCA (Class 3&4, Class 1&2 piggable)	$28-$87	$2-$6	$36-$110	$2-$7
Total	**$245-$667**	**$16-$44**	**$310-$842**	**$21-$56**

MAOP = maximum allowable operating pressure
1. Present value over 15-year study period.
2. Total divided by 15.

Table 4-8. Present Value of Cost Savings Benefits, Topic Area 1 (Millions, 2015$)[1]

7% Discount Rate		3% Discount Rate	
Total	**Average Annual**	**Total**	**Average Annual**
$2,668	$178	$3,366	$224

MAOP = maximum allowable operating pressure
1. Associated with MAOP verification for segments for which records are inadequate within high consequence area and Class 3 and 4 locations. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times MAOP and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods. Total is present value over 15-year study period; average annual is total divided by 15.

4.1.4 ADDITIONAL BENEFITS NOT QUANTIFIED

The benefit analysis is focused on the adverse safety consequences averted from postulated

incidents by detecting and repairing latent or future defects associated in pipeline segments. The assessment and repair of the pipeline serves to maintain the pipeline in better condition before serious degradation could occur. By requiring assessment on a periodic basis and the timely repair of pipeline defects, the proposed rule is expected to significantly contribute to the extension of the useful life of the pipeline, which represents a significant long term economic benefit not quantified in this analysis.

In addition, avoidance of future incidents results in fewer unplanned system outages, operating pressure restrictions, and potential service curtailments, which would result in future lost revenue for operators, which PHMSA did not quantify.

4.2 TOPIC AREA 2: IMP PROCESS CLARIFICATIONS

This section addresses benefits from the proposed integrity management program process clarifications. In general, PHMSA used the same analytical approach as for Topic Area 1 except that incident averted rate applies to the number of applicable defects in HCAs repaired sooner.

4.2.1 ANALYSIS ASSUMPTIONS

As described in section 3.2.4.1, PHMSA estimated that approximately 210 pipeline defects per year located in HCAs would meet the new criteria for one-year conditions and be repaired more promptly than currently required.

4.2.2 ESTIMATION OF BENEFITS

PHMSA does not have specific data with which to quantify the estimated safety benefit of sooner repairs. However, the total annual cost of accelerated repairs is relatively low. The estimated cost varies based on the rate at which the cost difference between the baseline costs and accelerated costs are discounted as described in Section 3.2. Based on the average incident consequences in HCAs (see Appendix E), between 0.10 (7% scenario) and 0.05 (3% scenario) incidents would need to be averted annually for monetized benefits to equal estimated costs (i.e., between 1-2.2 incidents over the 15-year study period in both scenarios). **Table 4-9** shows these results.

Table 4-9. Breakeven Analysis, Topic Area 2

Scenario	Annual Cost[1]	Average HCA Incident Consequences[2]	Break-Even Number of Incidents per Year[3]
7% interest rate	$3,350,528	$23,408,790	0.14
3% interest rate	$1,575,790	$23,408,790	0.07

1. See Table 3-43. Annual cost represents the change in time value of money of expedited repairs for the given interest rate
2. See Table E-3.
3. Calculated as annual cost divided by average incident consequences.

4.2.3 ADDITIONAL BENEFITS NOT QUANTIFIED

Clarifications to the threat identification processes, baseline assessment methods, preventive and mitigative measures, and periodic evaluations and assessments are beneficial to the continuous improvement of integrity management. Additionally, these clarifications emphasize the functions that must be accomplished, elaborate on the elements of effective

processes, and clearly articulate PHMSA's expectations in these areas. The proposed rule adds language from national consensus standards in the areas of validating risk models and conducting integrity assessments and remediating anomalies. PHMSA expects that emphasizing and clarifying these aspects of IM by incorporating them into the rule text may improve operator implementation of existing IM requirements. Enhancing implantation of IM would lead to further unquantified safety and environmental benefits and improved public confidence in the safe operation of new and existing gas transmission pipelines.

4.3 TOPIC AREA 3: MANAGEMENT OF CHANGE PROCESS IMPROVEMENT

This section provides analysis of benefits from improving management of change. The analytical approach is valuing the estimated incidents averted per year by the estimated average cost based on historical data.

4.3.1 ANALYSIS ASSUMPTIONS

PHMSA does not have specific data with which to quantify the estimated safety benefit of a programmatic or process oriented management system such as management of change. However, some extremely high consequence incidents have occurred in recent years in which inadequate change control, including field change control, contributed to the incident, including high-visibility incidents at San Bruno, CA, Bellingham WA (hazardous liquid pipeline) and Walnut Creek, CA (hazardous liquid pipeline). For example, the San Bruno incident was caused from a pup piece (a short piece of pipe) that was not qualified pipe. This pup piece was apparently inserted during a field change and was not properly approved or documented. An effective management of change process would prevent such erroneous substitutions of substandard material during pipeline construction. Management of change affects all aspects of pipeline design, construction, operation, and maintenance. For illustration, PHMSA assumed that one incident per year would be averted by the proposed management of change regulation.

4.3.2 ESTIMATION OF BENEFITS

Table 4-10 and **Table 4-11** show the calculation of safety benefits from Topic Area 3.

Table 4-10. Calculation of Safety Benefits, Topic Area 3 (Millions 2015$)

Incidents Averted per Year[1]	Average Cost per Incident[2]	Annual Benefits[3]
1	$0.8	$0.8

1. Source: PHMSA best professional judgment
2. See Table E-1
3. Calculated as incidents averted × average cost per incident.

Table 4-11. Present Value of Benefits, Topic Area 3 (Millions 2015$)

7% Discount Rate		3% Discount Rate	
Total[1]	Average Annual[2]	Total[1]	Average Annual[2]
$8.2	$0.5	$10.3	$0.7

1. Present value over 15-year study period.
2. Total divided by 15.

4.4 TOPIC AREA 4: CORROSION CONTROL

This section addresses benefits from corrosion control using the same analytical approach as for Topic Area 3.

4.4.1 ANALYSIS ASSUMPTIONS

This section describes the assumptions related to surveys, interference currents, and internal corrosion controls.

External Corrosion Coating Surveys and Close Interval Surveys

From 2010 through 2013, operators reported 31 reportable onshore incidents caused by external corrosion. For 20 of those incidents, operators reported the most recent annual cathodic protection (CP) survey date. Out of those 20 incidents, operators reported close interval survey (CIS) dates at or after the CP survey date for only 2 of the incidents. Requiring CIS to further investigate and correct CP deficiencies would reduce external corrosion incidents. The proposed regulations are expected to reduce but not completely eliminate failures caused by external corrosion. PHMSA does not have specific data to estimate the safety benefits of this provision. For illustration, PHMSA assumed that the proposed rule would avert approximately four incidents per year.

In addition to reducing external corrosion incidents caused by coating failures, the rule will also produce economic benefits in the form of reduced corrosion repairs necessary to prevent future incidents. Reduced pre-emptive repair benefits are not included in this analysis.

Interference Currents

From 2002 through 2013, operators reported 2 reportable incidents caused by interference current. This is an average of approximately 0.2 incidents per year that the proposed rule is targeted to address. PHMSA expects the proposed rule to effectively eliminate this pipeline failure cause, if properly implemented. Therefore, PHMSA assumed approximately 0.2 incidents per year would be averted.

Note that other external corrosion incidents may also have been caused by undetected interference currents, so that this estimate is conservative. In addition, proper cathodic protection will reduce the requirement for pipeline repairs necessary to prevent future incidents. Benefits from reduced pre-emptive repairs are not included in this analysis.

Internal Corrosion Controls

From 2010 through 2013, operators reported 60 reportable incidents caused by internal corrosion, 52 (87%) of which were attributed to known or suspected contaminants that PHMSA is addressing with the proposed rule. PHMSA expects the proposed rule to reduce but not completely eliminate failures caused by gas stream contaminants. Therefore, PHMSA assumed that the proposed rule would avert approximately three incidents per year.

In addition, reduced internal corrosion will yield additional benefits in the form of fewer repairs undertaken to prevent future incidents. Benefits from reduced pre-emptive repairs are not included in this analysis.

4.4.2 ESTIMATION OF BENEFITS

Table 4-12 shows the calculation of safety benefits from Topic Area 4. **Table 4-13** shows

the results over the study period.

Table 4-12. Calculation of Safety Benefits, Topic Area 4 ((Millions, 2015$)		
Incidents Averted per Year[1]	**Average Cost per Incident**[2]	**Annual Benefits**[3]
7.2	$0.3	$2.4
1. Source: PHMSA best professional judgment (4.0 + 0.2 + 3.0) 2. See Table E-5. 3. Calculated as incidents averted × average cost per incident.		

Table 4-13. Present Value of Benefits, Topic Area 4 (Millions 2015$)			
7% Discount Rate		**3% Discount Rate**	
Total[1]	**Average Annual**[2]	**Total**[1]	**Average Annual**[2]
$23.3	$1.6	$29.4	$2.0
1. Present value over 15-year study period. 2. Total divided by 15.			

4.5 PIPELINE INSPECTION FOLLOWING EXTREME EVENTS

This section provides analysis of benefits of inspecting gas transmission pipelines following extreme events. The analytical approach is the same as for Topic Areas 3 and 4.

4.5.1 ANALYSIS ASSUMPTIONS

From 2003 through 2013, pipeline operators reported 85 reportable incidents in which storms or other severe natural force conditions damaged pipelines, resulting in failure. Operators reported total damages for these incidents of over $104M. Although the proposed rule would not guarantee that pipeline inspections and repair could be accomplished before all storm damaged pipe would fail, it would require that operators conduct inspections and repair in a prompt and timely manner, thus preventing some incidents. For illustration, PHMSA assumed that 0.5 incidents per year would be averted by implementation of the proposed regulation. The benefits would result from requiring operators to discover pipeline damage and make repairs sooner than they would in the absence of this rule.

4.5.2 ESTIMATION OF BENEFITS

Table 4-14 shows the calculation of safety benefits from Topic Area 5. **Table 4-15** shows the results over the study period.

Table 4-14. Calculation of Safety Benefits, Topic Area 5 (2015$)		
Incidents Averted per Year[1]	**Average Cost per Incident**[2]	**Annual Benefits**[3]
0.5	$114,077	$57,039
1. Source: PHMSA best professional judgment 2. See Table E-6. 3. Calculated as incidents averted × average cost per incident.		

Table 4-15. Present Value of Benefits, Topic Area 5 (Millions 2015$)			
7% Discount Rate		**3% Discount Rate**	
Total[1]	**Average Annual**[2]	**Total**[1]	**Average Annual**[2]
$555,869	$37,058	$701,352	$46,757

Table 4-15. Present Value of Benefits, Topic Area 5 (Millions 2015$)			
7% Discount Rate		3% Discount Rate	
Total[1]	Average Annual[2]	Total[1]	Average Annual[2]
1. Present value over 15-year study period. 2. Total divided by 15.			

4.6 TOPIC AREA 6: MAOP EXCEEDANCE REPORTS AND RECORDS VERIFICATION

PHMSA did not have information to estimate the benefits of this provision from the prestatutory baseline to accompany the estimate of such costs.

4.7 TOPIC AREA 7: LAUNCHER/RECEIVER PRESSURE RELIEF

This section addresses benefits from the launcher and receiver pressure relief provisions.

4.7.1 ANALYSIS ASSUMPTIONS

Because most modern launchers and receivers already have the safety equipment that is the target of the proposed rule, and because PHMSA has no data with which to establish an incident rate, PHMSA assumed, for illustration, that one launcher/receiver event would be averted over the course of the 15-year study period.

4.7.2 ESTIMATION OF BENEFITS

Table 4-16 shows the calculation of safety benefits from Topic Area 7. **Table 4-17** shows the results over the study period

Table 4-16. Calculation of Safety Benefits, Topic Area 7		
Total Incidents Averted[1]	VSL (millions)[2]	Total Benefits (millions)[3]
1	$9.4	$9.4
VSL = value of statistical life 1. Source: PHMSA best professional judgment 2. Approximately $9.4 million (2015$; per Department of Transportation internal guidance). 3. Over the 15-year study period. Calculated as incidents averted × VSL.		

Table 4-17. Present Value of Benefits, Topic Area 7 (Millions 2015$)			
7% Discount Rate		3% Discount Rate	
Total[1]	Average Annual[2]	Total[1]	Average Annual[2]
$6.1	$0.4	$7.7	$0.5
1. Present value over 15-year study period. 2. Total divided by 15.			

4.8 TOPIC AREAS 1-7: ENVIRONMENTAL BENEFITS

Natural gas pipeline incidents release greenhouse gases, primarily methane, into the atmosphere. These emissions contribute to climate change and social costs, as described in Section 3.9 and Appendix B. This section provides estimates of the social benefits from avoiding GHG emissions due to incidents described in Sections 4.1 through 4.7. A summary of estimated incidents averted is provided in **Table 4-18**.

Table 4-18. Summary of Estimated Incidents Averted, Topic Areas 1-7								
Estimate	Topic Area							
	1	2	3	4	5	6	7	Total
Annual	5-15	n.e.	1	7	1	n.e.	0	14-24
Total[1]	74-221	n.e.	15	108	8	n.e.	1	205-353

Note: detail may not add to total due to independent rounding.
n.e. = not estimated
1. Calculated as annual estimate times 15 years.

PHMSA estimated the amount of natural gas, methane, and carbon dioxide releases that would be avoided each year based on the estimated number of incidents averted, historical average releases from incident reports, and assumptions regarding the composition of the gas. **Table 4-19** shows the data on gas released during incidents. In analyzing this data, PHMSA considered if the release ignited, as reported by the operator in the incident report (**Table 4-20**). If the release ignited, PHMSA applied an efficiency factor of 0.35 based on Stephens (2000)[44] and used 120 pounds of CO_2 produced per thousand cubic feet (MCF) of methane combusted to estimate the amount of CO_2 released from combusted methane (EPA, 1995).[45] **Table 4-21** shows these results.

Table 4-19. Gas Released During Gas Transmission Pipeline Incidents (2010 – 2014)			
Year	**Incidents**	**Natural Gas Released (MCF)**	**Average per Incident (MCF)**
2010	105	2,351,022	22,391
2011	114	2,718,692	23,848
2012	102	2,105,292	20,640
2013	103	1,688,265	16,391
2014	129	2,467,085	19,125
Total	**553**	**11,330,355**	**20,489**

Source: Gas Transmission Incident Reports
MCF = thousand cubic feet

Table 4-20. Ignition or Explosion of Gas Released During Gas Transmission Pipeline Incidents (2010 – 2014)		
Year	**Ignition or Explosion**	**No Ignition or Explosion**
2010	19	86
2011	13	101
2012	15	87
2013	11	92
2014	16	113
Total (%)	74 (13%)	479 (87%)

Source: Gas Transmission Incident Reports

[44] Stephens, M.J., *A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines*, Topical Report prepared for the Gas Research Institute. GRI-00/0189, October 2000.
[45] Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, AP-42, Fifth Edition, January 1995.

Table 4-21. Greenhouse Gas Emissions per MCF of Natural Gas Released		
Gas	**Methane (MCF)**	**Carbon Dioxide(lbs)**
No ignition or explosion[1]	0.96	1.5
Ignition[2]	0.62	41.7

lbs = pounds
MCF = thousand cubic feet
CH_4 = methane
CO_2 = carbon dioxide
1. MCF CH_4 = 1 MCF gas × 96% methane; lbs CO_2 = 1 MCF gas × 1.3% $C0_2$ × 114.4 lbs/MCF.
2. MCF CH_4 = 1 MCF gas × 96% methane ×1-0.35 combustion efficiency factor); lbs CO_2 = (1 MCF gas × 1.3% $C0_2$ × 114.4 lbs/MCF) + (1 MCH methane × 96% methane × 0.35 combustion efficiency factor).

Table 4-22 shows the estimated reduction in annual emissions.

Table 4-22. Greenhouse Gas Emission Reductions Per Year				
Scenario[1]	**Natural Gas Combusted (MCF)[2]**	**Natural Gas Not Combusted (MCF)[3]**	**CH_4 Emissions Reduction (MCF)[4]**	**$C0_2$ Emissions Reduction (lbs)[5]**
Low	37,556	243,098	256,006	1,926,905
High	64,487	417,423	439,588	3,308,688

MCF = thousand cubic feet
CH_4 = methane
CO_2 = carbon dioxide
1. Low scenario reflects low assumption of defect failures and avoided incidents; high scenario reflects high assumption of defect failures and avoided incidents.
2. Gas released × 13%
3. Gas released × 87%
4. (Combusted × 0.62) + (not combusted × 0.96); see tables 4-19 and 4-20.
5. (Combusted gas × 116 lbs. $C0_2$/MCF gas) + (not combusted gas × 1.5 lbs. $C0_2$).

To value the avoided emissions, PHMSA used the U.S. Social Cost of Carbon (SCC) Interagency Working Group's current estimates of SCC and estimates of SCM that were developed by Marten et al., (2014), as appropriate. The sum of these values is the total social benefits due to avoided greenhouse gas emissions (**Table 4-23**). See Appendix B for detailed calculations of these values.

Table 4-23. Summary of Total Climate Benefits, Topic Areas 1-7 (Millions 2015$)[1]		
Pollutant	**Avoided Emissions**	**Social Cost (3%)**
Methane (MCF)	3,840,090-6,593,818	$113.0-$194.0
Carbon dioxide (MT)	13,110-22,512	$0.6-$1.0
Total	**NA**	**$113.5-$195.0**

MCH = thousand cubic feet
MT = metric tons
1. Total over 15-year period calculated as emissions from Table 4-22 multiplied by 15 years and valued using the estimates in Appendix B.

In addition, pipeline incidents leading to the combustion of natural gas will also generate emissions of urban air pollutants, including carbon monoxide, nitrogen oxides, and

hydrocarbons. Uncontrolled burning from a pipeline incident is likely to be very inefficient compared with fuel burned in an engine or boiler, hence urban air pollutant emissions are likely to be relatively high in comparison with the amount of fuel combusted. "Rich" gas from gathering line incidents will generate more pollutants (particularly heavier hydrocarbons) than pipeline quality natural gas. Pipeline incidents that cause combustion of surrounding vegetation or structures will cause disproportionate emissions of urban air pollutants, and some hazardous air pollutants. PHMSA lacks a basis for making an estimate of the quantity of these emissions, and the social value may be location dependent.

4.9 SUMMARY OF BENEFITS

Table 4-24 provides a summary of safety benefits by topic area. Table 4-25 summarizes the total benefits climate change benefits of the proposed rule due to incidents, and therefore emissions, avoided.

Table 4-24. Present Value of Safety Benefits, Topic Areas 1-7 (Millions 2015$)

Topic Area	7% Discount Rate		3% Discount Rate	
	Total[1]	Annual[2]	Total[1]	Annual[2]
1	$245.5 -$667	$16.4 -$44.5	$309.7 -$841.5	$20.6 -$56.1
2	n.e.	n.e.	n.e.	n.e.
3	$8.2	$0.5	$10.3	$0.7
4	$23.3	$1.6	$29.4	$2.0
5	$0.6	$0.0	$0.7	$0.0
6	n.e.	n.e.	n.e.	n.e.
7	$6.1	$0.4	$7.7	$0.5
Total	**$283.5 -$705.0**	**$18.9 -$47.0**	**$357.8 -$889.6**	**$23.9 -$59.3**

n.e. = not estimated
1. Present value over 15-year study period.
2. Total divided by 15.

Table 4-25. Climate Change Benefits, Topic Areas 1-7 (Millions 2015$)

	Total[1]	Annual[2]
1	$40.9 -$122.3	$2.7 -$8.2
2	n.e.	n.e.
3	$8.3	$0.6
4	$59.7	$4.0
5	$4.1	$0.3
6	n.e.	n.e.
7	$0.6	$0.0
Total	**$113.5 -$195.0**	**$7.6 -$13.0**

n.e. = not estimated
1. Total value over 15-year study period.
2. Total divided by 15.

Table 4-26 synthesizes these results, including the cost savings benefits described in **Table 4-8**, to calculate the total benefits of Topic Areas 1-7.

Table 4-26. Present Value of Total Benefits, Topic Areas 1-7 (Millions 2015$)[1]				
Benefits Category	**7% Discount Rate**		**3% Discount Rate**	
	Total	**Average Annual**	**Total**	**Average Annual**
Safety	$283.5 -$705	$18.9 -$47.0	$357.8 -$889.6	$23.9-$59.3
Cost savings	$2,667.6	$177.8	$3,3655.7	$224.4
Climate change	$113.5 -$195.0	$7.6 -$13.0	$113.5 -$195.0	$7.6 -$13.0
Total	**$3,064.7 -$3,567.6**	**$204.3 -$237.8**	**$3,837.0 -$4,450.3**	**$255.8 -$296.7**
1. Total is present value over 15-year study period; average annual is total divided by 15.				

5. COMPARISON OF BENEFITS AND COSTS FOR TOPIC AREAS 1 THROUGH 7

This section provides a comparison of benefits and costs for Topic Areas 1 through 7 which apply to onshore gas transmission pipelines. This section also addresses alternatives to the proposed rule in these topic areas.

5.1 BENEFITS AND COSTS OF PROPOSED RULE

Sections 3.1 through 3.7 describe the cost estimates for each of the seven topic areas. Sections 4.1 through 4.8 describe the benefit estimates associated with these topic areas. Both the costs and benefits are dominated by Topic Area 1 which would require integrity assessments for approximately 16,000 miles of pipelines. The regulatory impact of other topic areas is relatively minor in comparison. The proposed rule, as described under Topic Area 1, would require that an initial integrity assessment be completed within 15 years of the effective date of the proposed rule. Therefore, 15 years is the timeframe for this analysis to analyze the entire initial assessment period. However, PHMSA expects the regulation to have long-term impact with benefits occurring long beyond the 15-year study period.

Tables 5-1 through **Table 5-6** provide a summary of the present value benefits and costs. For comparison, the total estimated social cost ($534 million at a 7% discount rate) is approximately one-third the consequence of the San Bruno incident (see Appendix D).

Table 5-1. Summary of Average Annual Present Value Costs, Topic Areas 1-7, 7% Discount Rate (Millions 2015$)

Topic Area	Compliance	Social Cost of Methane[1]	Total
1	$16.0	$1.8	$17.8
2	$2.2	$0.0	$2.2
3	$0.7	$0.0	$0.7
4	$6.3	$0.0	$6.3
5	$0.1	$0.0	$0.1
6	$0.2	$0.0	$0.2
7	$0.0	$0.0	$0.0
Total	**$25.4**	**$1.8**	**$27.3**

1. Using 3% discounted values (see Appendix B).

Table 5-2. Summary of Average Annual Present Value Costs, Topic Areas 1-7, 3% Discount Rate (Millions 2015$)

Topic Area	Compliance	Social Cost of Methane	Total
1	$20.2	$1.8	$22.0
2	$1.3	$0.0	$1.3
3	$0.8	$0.0	$0.8
4	$7.9	$0.0	$7.9
5	$0.1	$0.0	$0.1
6	$0.2	$0.0	$0.2
7	$0.0	$0.0	$0.0

Table 5-2. Summary of Average Annual Present Value Costs, Topic Areas 1-7, 3% Discount Rate (Millions 2015$)			
Topic Area	**Compliance**	**Social Cost of Methane**	**Total**
Total	**$30.5**	**$1.8**	**$32.3**

Table 5-3. Summary of Average Annual Present Value Benefits, Topic Areas 1-7, 7% Discount Rate				
Topic Area	**Safety**	**Cost Savings[1]**	**Climate[2]**	**Total**
1	$16.4 -$44.5[3]	$177.8	$2.7 -$8.2[3]	$196.9 -$230.5
2	n.e.	n.e.	n.e.	n.e.
3	$0.5	$0.0	$0.6	$1.1
4	$1.6	$0.0	$4.0	$5.5
5	$0.0	$0.0	$0.3	$0.3
6	n.e.	n.e.	n.e.	n.e.
7	$0.4	$0.0	$0.0	$0.4
Total	**$18.9 -$47.0**	**$177.8**	**$7.6 -$13**	**$204.3 -$237.8**

n.e. = not estimated
1. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods.
2. Using 3% discounted values. TA 1 includes range for uncertainty.
3. Range reflects uncertainty in incidents averted rates, see Table 4-2 and Table 4-3.

Table 5-4. Summary of Average Annual Present Value Benefits, Topic Areas 1-7, 3% Discount Rate (Millions 2015$)				
Topic Area	**Safety**	**Cost Savings[1]**	**Climate[2]**	**Total**
1	$20.6 -$56.1[3]	$224.4	$2.7 -$8.2[3]	$247.8 -$288.6
2	n.e.	n.e.	n.e.	n.e.
3	$0.7	$0.0	$0.6	$1.2
4	$2.0	$0.0	$4.0	$5.9
5	$0.0	$0.0	$0.3	$0.3
6	n.e.	n.e.	n.e.	n.e.
7	$0.5	$0.0	$0.0	$0.6
Total	**$23.9 -$59.3**	**$224.4**	**$7.6 -$13.0**	**$255.8 -$296.7**

n.e. = not estimated
1. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods.
2. Using 3% discounted values. TA 1 includes range for uncertainty in incidents averted rates (see Table 4-2 and Table 4-3).
3. Range reflects uncertainty in incidents averted rates, see Table 4-2 and Table 4-3.

Table 5-5. Summary of Average Annual Present Value Benefits and Costs, Topic Areas 1-7, 7% Discount Rate (Millions 2015$)			
Topic Area	**Average Annual Benefits**	**Average Annual Costs**	**Benefit: Cost Ratio**
1	$196.9 -$230.5[1]	$17.8	11.1-12.9
2	n.e.[2]	$2.2	n.e.
3	$1.1	$0.7	1.7
4	$5.5	$6.3	0.9
5	$0.3	$0.1	4.3
6	n.e.	$0.2	n.e.
7	$0.4	$0.0	18.5
Total	**$204.3 -$237.8**	**$27.3**	**7.5-8.8**

n.e. = not estimated
1. Reflects uncertainty in incident averted rates. See Tables 4-2 and 4-3.
2. Break even value of benefits would equate to approximately one incident averted over the 15-year study period.

Table 5-6. Summary of Average Annual Present Value Benefits and Costs, Topic Areas 1-7, 3% Discount Rate (Millions $2015)			
Topic Area	**Average Annual Benefits**	**Average Annual Costs**	**Benefit: Cost Ratio**
1	$247.8 -$288.6[1]	$22.0	11.3 -13.1
2	n.e.[2]	$1.3	n.e.[2]
3	$1.2	$0.8	1.5
4	$5.9	$7.9	0.8
5	$0.3	$0.1	4.5
6	n.e.	$0.2	n.e.
7	$0.6	$0.0	23.0
Total	**$255.8 -$296.7**	**$32.3**	**7.9 -9.2**

n.e. = not estimated
1. Reflects uncertainty in incident averted rates. See Tables 4-2 and 4-3.
2. Break even value of benefits would equate to less than one incident averted over the 15-year study period.

5.2 LIMITATIONS AND UNCERTAINTIES

There is substantial uncertainty in several parameters underlying the analysis including affected mileage, unit costs, effectiveness, and value of avoiding incidents. With respect to the affected mileage, commitments to expand assessment and repair programs beyond HCAs have already been made by the industry in PHMSA's workshops and in response to the ANPRM dated August 25, 2011 (76 FR 53086).[46] These commitments have the effect of reducing the compliance costs and the benefits associated with the proposed rule.

Also, in estimating costs and avoided risks of incidents, PHMSA relied on existing experience which reflects primarily assessment in HCAs. Extrapolation of this experience

[46] Letter from Terry D. Boss, Senior Vice President of Environment, Safety and Operations, Interstate Natural Gas Association of America (INGAA) to Mike Israni, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, dated January 20, 2012, "*Safety of Gas Transmission Pipelines*, Docket No. PHMSA-2011-0023"

could overstate costs in MCAs due to the lower density of development. There is also uncertainty regarding the effectiveness of the proposal in Topic Area 1 to reduce the risks of incidents. For example, NTSB (2015)[47] identified areas of integrity management where improvements can be made to further enhance the safety of gas transmission pipelines in HCAs. PHMSA sponsored research on the effectiveness of IM and IVP based on real-world experience shows that certain anomalies found in legacy pipe are not detected using IM.[48] However, the study does not provide a basis to estimate the number of defects that would be discovered by the proposed rule. The accuracy of PHMSA's estimates of incidents averted is largely dependent on the accuracy of the defect discovery rates shown in Table 4-1, and the estimated percentages of defects that, absent TA1's requirements, would result in incidents as shown in Table 4-2 (which are presented as ranges). In addition, there is no data on the extent of mileage that would meet the definition of an MCA.

Costs could also increase or decrease over time due to a variety of factors including technological improvement, changes in industry structure, and changes in prices. In particular, PHMSA expects ongoing development of new inline integrity assessment technologies to reduce the cost of ILI and to allow line segments that are currently unpiggable using conventional technology to use ILI without significant upgrade or replacement of the segment. A reduction in these assessment costs over time would further increase the net benefit of the proposed rule.

The benefits of reducing risks represent consequences from incidents reported by pipeline operators which do not include all consequences associated with incidents. Operators submit their casualty and direct loss/damage estimates only which may undervalue the impact of all consequences since other consequential costs, including indirect costs, to operators, other stakeholders, or society are not included. The inclusion of these unreported consequential costs of incidents would increase the estimated safety benefits associated with the proposed rule. The averages of reported consequences from past incidents could under- or overstate future consequences.

5.3 BENEFITS AND COSTS OF ALTERNATIVES

This section addresses alternatives to the proposed rule in Topic Areas 1 through 7.

Regulatory analyses typically consider the alternative of taking no action, maintaining the status quo. As a result, no new requirements would be levied. PHMSA considered the no action alternative for all Topic Areas. Sections 1-4 provide detailed discussion of the need for the proposed rule and benefits to be gained that justify a regulatory alternative. The sections below also note any particular considerations in this regard.

5.3.1 ALTERNATIVES FOR TOPIC AREA 1

This section discusses alternatives PHMSA considered to the proposed requirements in Topic Area 1.

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[47] National Transportation Safety Board (NTSB). 2015. Integrity Management of Gas Transmission Pipelines in High Consequence Areas. Safety Study NTSB/SS-15/01 PB2015-102735. Online at http://www.ntsb.gov/safety/safety-studies/Documents/SS1501.pdf.

[48] J.F. Kiefner and K. M. Kolovich. 2012. ERW and Flash Weld Seam Failures. Final Report to Batelle, U.S. Department of Transportation Agreement No. DTPH56-11-T-000003. September 24.

5.3.1.1 ALTERNATIVE 1: MORE STRINGENT MCA CRITERIA AND EXPANSION OF TESTING TO RE-ESTABLISH MAOP FOR ADDITIONAL PIPE

Alternative 1 provides:

- More stringent criteria for defining an MCA (reduces number of buildings and persons in the PIR from five to one)
- Integrity assessments of nonpiggable mileage in Class 1 and 2 locations
- Testing to re-establish MAOP for pipe susceptible to material or construction defects that were pressure tested to less than 1.25 times MAOP, and additional mileage in MCAs in Classes 1 and 2 that have not been pressure tested.

These additional criteria would more comprehensively address NTSB recommendations P-11-14 and P-11-15 (compared to the proposed rule).

PHMSA performed a quantitative estimate of the costs and benefits for this alternative. PHMSA used the same analysis approach and assumptions as described in Section 3.1 (costs) and 4.1 (benefits), with adjustments to account for changes in that the scope of the rule. PHMSA made the same assumptions for assessment of unpiggable Class 1 and 2 pipe as for other segments in the base analysis that are not piggable (i.e., used the same percentage of pressure test and direct assessment as for Class 3 and 4 locations). For benefits, PHMSA used the average consequences of incidents from 2003-2013 preventable by integrity management that occurred outside of HCAs excluding those that did not result in property damage, death, or injury (see Table E-9). The average incident severity for incidents prevented by integrity assessments and establishing MAOP may be lower if more stringent MCA criteria is applied because more stringent criteria would include pipeline that is in areas with fewer people and property. **Table 5-7** and **Table 5-8** show the resulting costs and benefits.

Table 5-7. Present Value Incremental Compliance Costs, Topic Area 1: Alternative 1 (Millions 2015$)[1]

Topic Area	Miles	Annual (7%)	Total (7%)	Annual (3%)	Total (3%)
Re-establish MAOP: HCA > 30% SMYS	909	$0.4	$5.8	$0.5	$7.4
Re-establish MAOP: Inadequate Records	4,363	$6.9	$103.0	$8.7	$130.0
Integrity Assessment: MCA[2]	18,294	$24.9	$373.5	$31.4	$471.2
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; MCA Class 1 and 2[3]	8,607	$5.0	$74.4	$6.3	$93.9
Total	**32,173**	**$37.1**	**$556.7**	**$46.8**	**$702.4**

1. Total over 15 years; annual is total divided by 15.
2. Represents change from proposed rule (1 building MCA criteria; nonpiggable Class 1 and 2 miles must be assessed).
3. Represents change from proposed rule (1 building MCA criteria; MCA Class 1 & 2 miles must be assessed).

Table 5-8. Present Value Safety Benefits,[1] Topic Area 1: Alternative 1 (Millions 2015$)[2]					
Topic Area	**Annual Incidents Averted**	**Annual (7%)**	**Total (7%)**	**Annual (3%)**	**Total (3%)**
Re-establish MAOP: HCA > 30% SMYS	0.2-0.6	$3.5-$8.6	$52.1-$128.4	$4.4-$10.8	$65.8-$162
Re-establish MAOP: Inadequate Records	1.4-3.8	$9.4-$24.7	$140.8-$371.1	$11.8-$31.2	$177.7-$468.2
Integrity Assessment: MCA	6.1-18.9	$2.9-$13.3	$44.2-$200.1	$3.7-$16.8	$55.8-$252.5
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; MCA Class 1 and 2	2.6-8.7	$2.5-$10.1	$36.8-$151.2	$3.1-$12.7	$46.5-$190.8
Total	**10.4-32.0**	**$18.3-$56.7**	**$274.0-$850.9**	**$23.0-$71.6**	**$345.7-$1,073.6**
1. Does not include cost savings or environmental benefit 2.Total over 15 years; annual is total divided by 15. Based on average consequences per MCA incident of $0.7 million (see Table E-9).					

PHMSA estimated that this alternative would provide approximately 31,000 miles of additional pipe that contained residences or occupied sites inside the PIR with the additional protections afforded other segments covered by the proposed rule.

In addition, a major constituency of the pipeline industry (INGAA) has committed to apply IM principles to all segments where any persons are located. This is comparable to PHMSA's MCA definition contemplated in this alternative, thus showing industry support for the policy objective of applying additional protections for any segments with a house/site inside the PIR.

5.3.1.2 TOPIC AREA 1 - ALTERNATIVE 2: MORE LIMITED SCOPE OF MCAS BY EXCLUDING PIPELINES LESS THAN 8-INCHES DIAMETER

PHMSA considered restricting the application of MCA requirements to pipe segments that are ≥8" in diameter. Exempting MCA pipe <8" in non-HCA Class 1 or non-HCA Class 2 would result in minimal mileage reduction to the scope of the rule, because:

- Less 15% of onshore natural gas transmission line mileage is smaller than 8" in diameter.
- The PIR for small diameter is very small.
- The statutory mandate to verify MAOP for any pipe in HCA, Class 3, and Class 4 locations for which records are insufficient to confirm the established MAOP would still apply to these smaller pipe sizes. Thus, pipe segments <8" in diameter that meet the Act's criteria would still require an integrity assessment, however they would not require additional assessments under the Act.

To illustrate, the area of an impact circle is calculated as $A = (0.69\pi)^2 \times P \times D^2$ where P = operating pressure and D = the diameter[49]. All else equal, a 4" diameter pipe segment impacts a quarter less area than an 8" diameter pipe segment. PHMSA estimated that the pipeline mileage which would require an integrity assessment would be reduced by only

[49] Area = πr^2 where the radius is the PIR equation in 49 CFR §192.903.

about 4%. With this alternative, some residences would remain unprotected even though they were within the PIR.

5.3.1.3 TOPIC AREA 1 - ALTERNATIVE 3: EXPAND SCOPE OF HCA INSTEAD OF CREATING MCA

PHMSA considered expanding the scope of HCAs instead of creating MCAs. PHMSA received a number of comments on this approach in response to the 2011 ANPRM. This approach would be counter to a graded approach based on risk (i.e., risk based gradation of requirements to apply progressively more protection for progressively greater consequence locations). By simply expanding HCAs, PHMSA would be simply lowering the threshold for what is considered “high consequence.”

Expanding HCAs would require that all IM program elements be applied to pipe located in a newly designated HCA. The proposed rule would only apply three IM program elements (assessment, periodic reassessment, and remediation of discovered defects) to the category of pipe that has lesser consequences than HCAs (i.e., MCAs), but not to segments without any structure or site within the PIR (arguably “low consequence areas”). **Table 5-9** summarizes this risk-based, graded approach to application of IM requirements.

Table 5-9. Risk-based Gradation for Application of IM Program Elements

Category	Program Elements Applied
High Consequence Areas	All, including risk analysis preventive/mitigative measures, assessment, periodic reassessment, and remediation of discovered defects five year reassessment interval, rapid repair of discovered anomalies, plus non-IM prescriptive safety standards
Moderate Consequence Areas	Assessment, periodic reassessment, and remediation of discovered defects, plus non-IM prescriptive safety standards
Segments with no buildings intended for human occupancy or identified site or occupied site or major highway ROW within the PIR	Non-IM prescriptive safety standards only

Long term reassessment costs would approximately triple based on an almost three to one ratio of reassessment interval. Also, there would be additional costs to apply other program elements (most notably the risk analysis and preventive/mitigative measures program elements) to additional segments.

5.3.1.4 TOPIC AREA 1 - ALTERNATIVE 4: APPLY THE PROPOSED REQUIREMENTS TO ALL NON-HCA PIPE SEGMENTS

PHMSA considered expanding the proposed requirements such that they would apply to all non-HCA gas transmission pipelines. However, this option would dilute the impact of operator’s maintenance budgets by requiring assessments on segments deemed to be in “low consequence” locations (i.e., segments in locations without any structure intended for human occupancy or occupied site inside the PIR). PHMSA estimated that approximately 59,000 miles of onshore gas transmission pipeline would meet the definition of MCA (proposed) or HCA. The remaining 243,000 miles of gas transmission pipeline would not be in a location that would contain any structures intended for human occupancy, or identified site, or occupied site, or major highway right-of-way. Although it is possible that someone

could still be injured at such locations (e.g., persons in transient nearby at the time of a failure, workers performing maintenance on the pipeline, other parties performing excavation activities near the pipeline, etc.), PHMSA expects that the increase in benefit would be incremental, and not proportional to the cost.

5.3.1.5 TOPIC AREA 1 - ALTERNATIVE 5: ACCELERATE THE COMPLIANCE DEADLINE AND SHORTEN THE REASSESSMENT INTERVAL

PHMSA considered shorter a compliance deadline (ten years) and a shorter reassessment interval (15 years) for MCA assessments. The assessment timeframes in the proposed rule apply relaxed timeframes to MCAs, compared to HCAs.

The industry was originally required to perform baseline assessments for approximately 20,000 miles of HCA pipe within approximately eight years. PHMSA estimated that approximately 41,000 miles of pipe would require an assessment within 15 years under this proposed rule, thus constituting a comparable level of effort on the part of industry.

The maximum HCA reassessment interval is 20 years for low stress pipe.[50] The 20 year interval aligns with the longest interval allowed for any HCA pipe, which is 20 years for pipe operating less than 30% SMYS.[51] A reassessment interval of 15 years for MCAs would be shorter than the reassessment interval for some HCAs.

PHMSA also considered that compliance with the proposed rule would be performed in parallel with ongoing HCA reassessments at the same time, thus resulting in greater demand for ILI tools and industry resources than during the original IM baseline assessment period. In addition, the proposed rule incorporates other assessment goals, including IVP, MAOP verification, and material documentation, thus constituting a larger/more costly assessment effort than originally required under IM rules. For the above reasons, the proposed rule would require full utilization or expansion of industry resources devoted to assessments. Therefore, compressing the timeframes could be infeasible. PHMSA also considered the possibility that demands on the industry’s assessment capability might drive assessment costs higher.

5.3.1.6 TOPIC AREA 1 – ALTERNATIVE 6: PERFORM PRESSURE TESTING TO VERIFY MAOP FOR HCAS AND CLASS 3 AND CLASS 4 LOCATIONS

Section 23 of the Act specifies that PHMSA require operators to (1) re-confirm MAOP for pipelines in HCAs and Class 3 and Class 4 locations if records are not available and (2) issue regulations requiring that operators test previously untested pipeline segments in HCAs. Both of these activities would conventionally require a pressure test in accordance with subpart J of Part 192. This approach would mimic the regulations issued by CPUC in the aftermath of the San Bruno incident, in response to the NTSB recommendations that are related to the mandates in Section 23 of the Act.

PHMSA performed a screening benefit-cost evaluation for such pressure testing, limited to HCAs and Class 3 and Class 4 locations. The screening evaluation used the following inputs from the detailed analysis described in sections 3 and 4.

[50] See 49 CFR 192.939(b)(6)
[51] Note, however, that Confirmatory Direct Assessment (CDA) would not be required for MCAs at seven year intervals, as is required for HCAs.

- Segment mileage within the scope of this alternative from the estimates for IVP mileage in Table 3.1-4. PHMSA used the subset of proposed IVP mileage estimated for HCAs (3,158), Class 3 non-HCAs (2,514), and Class 4 non-HCAs (2) for a total of 5,674miles.
- PHMSA applied the same unit costs for pressure tests as for Section 3.1 of the analysis. The mean costs for the small, medium, and large diameter subsets were averaged to approximate a weighted average unit cost as described in Table 3-15. For this screening analysis PHMSA used the midpoint between the intrastate and interstate values ($215,248 per mile).
- The benefit estimated from incidents averted from pressure test failures is based on applying the pressure test defect detection and failure rates shown in Appendix C (Table C-2) using the process described in section 4.1.2.2.2. The results were scaled in proportion to the mileage estimate for this alternative (5,674).
- To calculate benefits, PHMSA multiplied the estimated incidents averted for HCA mileage by the average HCA incident consequence of $23 million (Appendix E; Table E-3) and the Non-HCA incidents averted by the class 3 and class 4 non-HCA average incident consequence of $0.1M (Appendix E; Table E-8)

The results of this screening evaluation are an estimated total cost for this alternative of $1.22 billion and total benefit of $856 million (nominal values).

5.3.1.7 TOPIC AREA 1 – ALTERNATIVE 6: NO ACTION

As discussed above, commitments to expand assessment and repair programs beyond HCAs have already been made by INGAA[52] in PHMSA's workshops and in response to the ANPRM dated August 25, 2011 (76 FR 53086). These commitments have the effect of reducing the compliance costs and the benefits associated with the proposed rule, and would improve safety under the no action alternative.

5.3.2 ALTERNATIVE FOR TOPIC AREA 2: NO ACTION

With respect to the no action alternative for Topic Area 2 requirements, the Act requires PHMSA to issue regulations on some of the topics addressed in the proposed rule, including seismic risk (Section 29 of the Act), and a technical correction regarding extension of reassessment intervals [Section 5(e) of the Act].

5.3.3 TOPIC AREA 3 ALTERNATIVE 2: EXTEND COMPLIANCE DEADLINES

One option to reduce the cost of the proposed rule is to extend the new compliance deadlines for development and implementation of MoC processes that apply to all gas transmission pipelines.

Extending the regulatory compliance deadlines would not reduce costs, though it would potentially defer costs by spreading them over a longer time period. Deferral would only

[52] Letter from Terry D. Boss, Senior Vice President of Environment, Safety and Operations, Interstate Natural Gas Association of America (INGAA) to Mike Israni, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, dated January 20, 2012, "*Safety of Gas Transmission Pipelines*, Docket No. PHMSA-2011-0023"

reduce costs if there are logistical bottlenecks to faster implementation. PHMSA is not aware of any logistical bottlenecks within the proposed timeframe that would raise implementation costs within the scope of the proposed compliance deadline. Although PHMSA did not explicitly analyze this alternative, generally, deferring a project with positive discounted net benefits will reduce net benefits.

Further, extending the compliance deadlines would potentially defer achieving the intended goal of formally controlling changes to pipeline systems and facilities during the period when the compliance deadline would be delayed. While pipeline incidents are not typically attributed to change management as a primary cause, it is a critical element in ensuring that pipeline operators evaluate the safety and operating parameters of their systems based upon up-to-date and accurate information about their systems. Effective Management of Change is an important complement to the assessments required by the Integrity Management Program generally and this proposes rule, because operators will be making changes to their pipelines as they repair anomalies detected by the required assessments. Failing to put change management procedures in place ahead of the expanded inspection regime risks injecting potentially hazardous inaccuracies into operator data as their systems evolve. An undocumented field change (usage of non-pipe grade pup pieces) was a major contributing factor of the San Bruno incident, according to NTSB.

Thus, this alternative is not considered for further development in this analysis.

5.3.4 ALTERNATIVES FOR TOPIC AREA 4

PHMSA considered a number of technical alternatives for enhanced corrosion control during development of the proposed rule. Examples include:

- Holiday testing (“jeeping”) in the trench with the pipe being supported and then moving the supports to check under them.
- Premium quality backfill such as clean washed sand bedding
- Second layer of coating to protect the corrosion protection coating from damage
- Additional gas stream processing/cleaning

The above alternatives would be more expensive to implement, without any expected appreciable benefit, and therefore were not considered further in this analysis.

5.3.5 ALTERNATIVE FOR TOPIC AREA 5: EXTEND COMPLIANCE DEADLINES

PHMSA considered extending the compliance deadlines for development or revision of procedures to specify that operators are to conduct surveillances following extreme weather or natural disaster, or similar events. Delaying compliance deadlines would not reduce total costs, though some costs would be deferred and spread out over a longer time period. Deferral would only reduce costs if there are logistical bottlenecks to faster implementation. PHMSA is not aware of any logistical bottlenecks that would raise implementation costs within the scope of the proposed compliance deadline. Although PHMSA did not explicitly analyze this alternative, generally, deferring a project with positive discounted net benefits will reduce net benefits.

Delaying compliance with deadlines would potentially have the same adverse consequences

as taking no regulatory action for the time period before compliance would be required. Each year, hurricanes, floods, mudslides, tornadoes, and other extreme events place pipelines at a greater risk of failure. From 2003 through 2013, pipeline operators reported 85 reportable incidents in which storms or other severe natural force conditions damaged pipelines, resulting in failure. Inspections triggered by the proposed rule should lead to the detection and repair of some event-induced damage, thus reducing the frequency of both immediate and some future incidents.

Because this is a relatively low cost proposal, and cost savings would be minimal compared to the potential benefit of prompt implementation, this alternative was not considered for further development in this analysis.

5.3.6 ALTERNATIVE FOR TOPIC AREA 7

This section discusses alternatives for Topic Area 7.

5.3.6.1 ALTERNATIVE 1: NO ACTION

Not taking action would continue the exposure of a small number of pipeline workers to routine safety hazards due to potentially high pressures within launchers and receivers. Hazards due to the high pressures could potentially result in serious injury or death. Thus, PHMSA did not consider this alternative further.

5.3.6.2 ALTERNATIVE 2: EXTEND COMPLIANCE DEADLINES

PHMSA considered extending the compliance deadlines associated with the development of design and testing specifications and the design, installation and testing of the launcher and receiver safety devices. This alternative would not reduce total costs, though it would defer costs and spread them over a longer time period. Deferral would only reduce costs if there are logistical bottlenecks to faster implementation. PHMSA is not aware of any logistical bottlenecks that would raise implementation costs within the scope of the proposed compliance deadline. Although PHMSA did not explicitly analyze this alternative, generally, deferring a project with positive discounted net benefits will reduce net benefits.

Because of the large increase in-line inspection assessment required by the proposed rule, delaying the compliance deadline would expose persons to avoidable risks. Delaying action would continue exposure of a small number of pipeline workers to routine safety hazards due to potentially high pressures within launchers and receivers. Hazards due to the high pressures could potentially result in serious injury or death. Thus, PHMSA did not consider this alternative for further development in this analysis.

6. BENEFIT PERTAINING TO TOPIC AREA 8 (GAS GATHERING LINES)

PHMSA currently regulates only an estimated 3% of the total onshore gas gathering infrastructure mileage. It is essential to begin collecting incident and infrastructure data on all of the currently unregulated mileage, to better identify, characterize, and assess its risk and inform future rulemaking. The proposed rule would apply new safety provisions to approximately 69,000 miles of the currently unregulated onshore gas gathering lines. Additionally, the proposed rule would mandate reporting for all of the approximately 356,000 miles of currently unregulated lines. Note that offshore gathering lines are currently subject to both the reporting and safety provisions of PHMSA's regulations.

6.1 DESCRIPTION OF THE TARGETED THREATS

Excavation damage remains a leading cause of onshore pipeline incidents. The approximately 69,000 miles of higher-stress and larger-diameter gas gathering lines that would be newly regulated under the proposed rule would be subjected to select safety provisions of PHMSA's requirements intended to prevent excavation damage.

PHMSA incident data reported over the past 20 years shows that nearly half (49%) of incidents are caused by corrosion. The majority (86%) of those are caused by internal corrosion. High moisture content, which can lead to internal corrosion, is typical for unprocessed or partially processed gas that many gathering lines transport. Corrosion failures are sensitive to operating stresses; pipelines at higher operating pressures and higher stress levels are more likely to rupture (instead of slowly leak) when the pipe wall is thinned due to corrosion. Under the proposed rule, the 68,749 miles of higher-stress and larger-diameter gathering lines would also be subjected to the safety provisions of PHMSA's requirements intended to prevent internal and external corrosion.

6.2 IDENTIFICATION OF THE SAFETY PERFORMANCE BASELINE

PHMSA expects that safety benefits would be achieved by reducing the potential for corrosion and excavation damage incidents that could affect the 69,000 miles of the higher-stress, larger-diameter onshore gathering lines by regulating them under the proposed rule. The safety performance baseline for this proposed rule is the performance of these gas gathering lines in their unregulated state. Because these lines are currently unregulated by PHMSA, PHMSA has no data upon which to establish this baseline performance directly, and, instead, has utilized incident data that is available on comparable regulated lines.

PHMSA established the range of actual incident rates on regulated gas gathering lines in the years prior to PHMSA's 2006 rulemaking referenced earlier in this RIA. (This 2006 rule selectively applied corrosion, excavation damage, and other safety measures comparable to those proposed in this rule to a new category of similar gas gathering lines, so safety performance after this time period would be less representative of an unregulated state.) Assuming that the current performance of unregulated gas gathering lines is generally less safe than for regulated gas gathering lines, PHMSA established a typical high value for incident rates for the time period prior to 2006, with this value approximating the baseline safety performance of unregulated gas gathering lines.

As a result, and for the purposes of this analysis, PHMSA assumed a baseline incident rate for corrosion and excavation damage incidents of 0.329 incidents per 1,000 miles per year. This value represents the average corrosion and excavation damage incident rate on unregulated, onshore gathering lines for five years prior to the implementation of corrosion control and damage prevention requirements (**Table 6-1**). This 0.329 average incident rate equates to a baseline of 22.6 corrosion and excavation damage incidents per year on these currently unregulated onshore gas gathering lines, as shown in **Table 6-2**.

Table 6-1. Safety Performance Baseline Calculation

Year	Corrosion and Excavation Damage Incidents[1]	Onshore Gathering Miles[2]	Incidents per 1000 Miles[3]
2001	5	17,562	0.285
2002	3	17,426	0.172
2003	1	16,426	0.061
2004	13	17,397	0.747
2005	6	16,220	0.370
Total	**28**	**85,031**	**0.329**

1. Source: Gas Transmission and Gas Gathering Incident Reports, onshore gathering lines corrosion and excavation damage
2. Gas Gathering Annual Report
3. Incidents divided by mileage times 1,000 miles.

Table 6-2. Baseline Incident Rate

Estimated Corrosion and Excavation Damage Incident Rate (per 1,000 miles per year)	Unregulated Higher-Stress, Larger-Diameter Onshore Gas Gathering Mileage	Estimated Corrosion and Excavation Damage Incidents per Year on Unregulated Lines (incidents per year)
0.329	68,749	22.6

Since PHMSA currently regulates only 14,540 miles of onshore gas gathering lines, its consequence data for gathering line incidents is extremely limited. Analysis of this data is especially constrained if limited to only those incidents caused by corrosion and excavation damage. The consequences of individual incidents vary considerably; the consequences of a relatively few incidents cannot be reliably extrapolated to a much larger population. PHMSA does have a significant amount of incident data for gas transmission pipelines, which have been regulated for many years. The characteristics of onshore gas transmission pipelines, in terms of the operating pressures and quantities of gas transported, can be adjusted for Class location and used to approximate the potential consequences from the higher-stress, larger-diameter onshore gas gathering lines that would be covered under the proposed rule. Therefore, PHMSA used reported gas transmission corrosion and excavation damage incident data for onshore Class 1 and Class 2 locations to analyze the expected benefits resulting from the proposed rule.

Appendix E (Table E-7) summarizes the reported safety consequences of corrosion and excavation damage incidents in Class 1 and Class 2 locations reported between 2003 and 2013. The average consequences (fatalities, injuries, and property damage) per incident

from the reported data are then applied to the number of incidents expected to occur (29.4 per year) to estimate the baseline consequences per year for the 69,000 miles of higher-stress, larger-diameter onshore gas gathering lines to be newly-regulated under the proposed rule. **Table 6-3** below summarizes these consequences on a per incident basis. Table **6-4** shows the estimation of baseline consequences.

Table 6-3. Average Consequences per Incident on Gas Transmission Systems in Class 1 and 2 Locations from Corrosion or Excavation Damage

Category	Number	Value
Fatalities[1]	0.03	$264,375
Injuries[1]	0.06	$61,68
Evacuations[2]	11.7	$17,517
Other	NA	$175,447
Total	NA	$519,027

Source: See Appendix E (Table E-7)
1. DOT VSL guidance, $9.4M VSL, factor .105 for serious injury.
2. Based on estimate of approximate cost of $1,500 per evacuation.

Table 6-4. Estimated Baseline Consequences Per Year

Incidents	Fatalities[1] (Count)	Injuries[2] (Count)	Evacuation Cost (Count)	Other Incident Costs	Total Costs
22.6	$5,979,708 (0.6)	$1,395,265 (1.4)	$396,209 (264)	$3,968,314	$11,739,495

VSL= Value of Statistical Life
1. Valued using a VSL of $9.4M per Departmental guidance (https://www.transportation.gov/sites/dot.gov/files/docs/VSL2015_0.pdf).
2. Valued using 0.105 times the VSL ($987,000), also per Departmental guidance.

6.3 ESTIMATE OF SAFETY BENEFITS FOR NEWLY-REGULATED TYPE A, AREA 2 PIPELINES

The proposed application of regulations targeting corrosion and excavation damage prevention will result in safety improvements for the 69,000 miles of newly-regulated lines. PHMSA's regulations have been very effective in these areas in the past, reducing the percentage of incidents caused by corrosion and excavation damage on onshore gas transmission pipelines in half since 1995, and more so over the longer-term. PHMSA expects similar improvements due to this rule to commence at the effective date of the proposed rule and occur over time for these newly-regulated lines. The pace of this improvement is expected to be accelerated because of industry's and operators' experiences in applying corrosion and excavation damage best practices as proven compliance strategies on currently regulated facilities.

The regulatory requirements for Type A Area 2 gas gathering segments most closely approximates existing requirements to Type B gathering lines in 49 CFR §192.9(d). PHMSA therefore assumed that the rate of corrosion and excavation damage incidents on Type B gathering lines approximates the incident rate on newly regulated Type A Area 2 lines. Since 2010, there has been only one corrosion or excavation damage related incident on a Type B miles (6,093 miles in 2014). As shown in **Table 6-5**, this equates to an expected incident rate of 0.042 per 10,000 miles.

Table 6-5: Safety Performance of Type B Gas Gathering Pipelines			
Year	**Corrosion and Excavation Damage Incidents[1]**	**Type B Miles[2]**	**Incidents per 1000 Miles[3]**
2010	1	5,344	0.187
2011	0	5,156	0.000
2012	0	3,633	0.000
2013	0	3,664	0.000
2014	0	6,093	0.000
Total	1	23,891	0.042

1. Gas Transmission and Gas Gathering Incident Reports, onshore gathering lines corrosion and excavation damage
2. Gas Gathering Annual Report
3. Incidents divided by mileage times 1,000 miles.

PHMSA assumed that an initial improvement from 0.329 to 0.2 incidents per 1,000 miles. In years 2-5 the incident rate per 1,000 mile falls to 0.1 while periodic components of the rule are implemented. After year 5 the incident rate stabilizes at the historical Type B incident rate. **Table 6-6** shows the expected incidents averted (totaling 271 over the 15-year period; 18 on average annually) and associated benefits for these periods. **Table 6-7** shows the estimated benefits over the 15-year study period.

Table 6-6. Calculation of Safety Benefits, Topic Area 8 (Millions 2015$ per year)						
Period	**Incidents Avoided per year**	**Value of Avoided Fatalities[1]**	**Injuries[2]**	**Evacuations[3]**	**Other Incident Costs[4]**	**Average Benefits Per Year**
Year 1	8.9	$2.3	$0.5	$0.2	$4.6	$7.7
Years 2-5	15.7	$4.2	$1.0	$0.3	$8.2	$13.6
Years 6-15	19.9	$5.3	$1.2	$0.3	$10.3	$17.1

1. Calculated as incidents avoided times VSL ($9.4 million in 2015$).
2. Calculated as incidents avoided times VSL ($9.4 million in 2015$) times 0.105.
3. Calculated as number of evacuations times $1,500 (PHMSA best professional judgment).
4. Calculated as average other incident damages times incidents averted (see Table E-7).

Table 6-5 presents the results of the safety benefits analysis for expanded safety regulation of certain gathering lines.

Table 6-7: Summary of Safety Benefits for Expanded Gathering Line Regulations[1]			
Average Annual (7%)	**Total (7%)**	**Average Annual (3%)**	**Total (3%)**
$9.7	$145.5	$12.5	$188.0

1. Based on expected stream of benefits from Table 6-4. Average annual is total discounted benefits divided by 15 years.

6.4 ESTIMATE OF ENVIRONMENTAL BENEFITS FOR NEWLY-REGULATED TYPE A, AREA 2 PIPELINES

Natural gas transported in gathering pipelines contains the same heat-trapping gases as the

gas transmission lines discussed in Section 4.8, with a slightly different set of components and percentage composition. The methodology for calculating the environmental benefit used in Section 4.8 is also utilized for this topic area.

Reduction of the potential number of incidents caused by corrosion and excavation damage, as described in Section 6.2.4, would reduce the amount of natural gas released to the atmosphere and the resultant GHG. The reduction in GHG would reduce the external costs associated with global warming.

Using historical incident data (**Table 6-8**) and assuming the gas composition in gathering lines averages 90% methane and 3% carbon dioxide by volume, PHMSA estimated the amount of natural gas, methane, and carbon dioxide releases that would potentially be avoided each year. When analyzing the historical data, PHMSA considered whether the release ignited, however PHMSA did not identify a gas gathering incident involving ignition or explosion of gas. PHMSA estimated the expected yearly reductions in methane and carbon dioxide released to the atmosphere as GHG using a similar methodology used to estimate the reduction in safety consequences. These amounts are shown in **Table 6-9** for the 15-year study period.

Table 6-8. Type A and Type B Gathering Line Incidents

Year	Incidents	Gas Released (MCF)	Average per Incident
2010	5	5,805	1,161
2011	4	27,413	6,853
2012	4	13,670	3,418
2013	0	0	0
2014	0	0	0
2015	1	25	20
Total	**14**	**46,913**	**3,351**

Source: PHMSA Gas Transmission and Gas Gathering Incident Reports

Table 6-9. Estimate of Reductions in Natural Gas, Methane, and Carbon Dioxide Released[1]

Period	Annual Releases Averted		
	Natural Gas (MCF)[1]	Methane (MCF)[2]	Carbon Dioxide (MT)[3]
Year 1	29,718	26,746	46
Years 2-5	52,755	47,480	82
Years 6-15	66,577	59,920	104
15-Yr Total	**906,512**	**815,861**	**1,411**

MCF = thousand cubic feet
MT = metric tons
1. Calculated as average incidents avoided per year times historical average natural gas releases from gas gathering incidents.
2. Calculated as natural gas released times 0.90.
3. Calculated as natural gas released times 0.03 times 114.4 lbs/MCF carbon dioxide.

To estimate the environmental benefit, PHMSA followed the guidelines established by the Interagency Working Group on SCC. See Appendix B for a detailed discussion of the SCC

and SCM. The social cost of GHG emissions reductions calculated for this topic area is for the 15-year study period. PHMSA applied the 3% discounted SCC/SCM values to both the 7% scenario and the 3% discount rate scenarios. The yearly environmental benefit estimates for this topic area are shown in **Table 6-10**. The present value of estimated environmental benefits total approximately $26 million at a 3% discount rate.

Table 6-10. Calculation of Benefits Per Year Based on Reductions in Volumes Emitted (3% Discount Rate)

Period	Methane		Carbon Dioxide		Average Benefits Per Year
	MCF	Average Benefit	Metric Tons	Average Benefit	
Year 1	26,746	$660,888	46	$1,758	$662,646
Years 2-5	47,480	$1,225,579	82	$3,326	$1,228,905
Years 6-15	59,920	$1,877,181	104	$4,799	$1,881,980

MCF = thousand cubic feet
1. Emissions calculated as expected incidents avoided times emission per incident. Values are the average of the product of emissions and the SCC/SCM value over the identified year range

Table 6-11 presents the total climate change benefits due to reductions in gas gathering incident rates.

Table 6-11. Total Environmental Benefits

Pollutant	Emissions	Social Benefit (3%)
Methane (MCF)	815,861	$24,335,016
Carbon dioxide (MT)	1,411	$63,049
Total	**NA**	**$24,398,065**

MCF = thousand cubic feet
MT = metric ton

6.5 ESTIMATE OF BENEFITS FOR OTHER CURRENTLY UNREGULATED GATHERING PIPELINES

Except for the 69,000 miles of higher-stress, larger-diameter lines, the proposed rule would apply only mandatory reporting requirements to the other currently unregulated gathering lines. Thus, no quantifiable reductions in incidents or natural gas releases are projected for those lines. The primary purpose of the proposed new mandatory reporting requirement is to enable PHMSA to gather data to improve its ability to analyze the lines for safety performance and risk. Although benefits are not readily quantifiable, PHMSA expects this information to inform decision-making and affect regulatory and safety outcomes in the future once the existing risks are better understood.

6.6 ADDITIONAL BENEFITS NOT QUANTIFIED

This analysis quantifies benefits from the expected prevention incidents and their consequences. PHMSA did not attempt to quantify other benefits, such as reductions in leaks and failures that do not meet the thresholds for “incident” reporting.

However, not quantified in the benefit-cost analysis for this topic area, PHMSA considers there would likely be additional, qualitative benefits, including:

- Reporting requirements for a substantial new population of gas gathering pipelines would enhance PHMSA's and operators' understanding of gas gathering pipeline risk. More knowledge about these pipeline systems would inform future risk based inspection, regulation, and operator maintenance of these lines.
- Federal safety standards for Type A Area 2 gathering lines would reassure members of the public in gas extraction regions that the segments with the greatest potential consequences are being operated in a safe and responsible manner.
- Pipeline operators may realize additional benefits through improved operating efficiencies realized from less product loss, less energy required to re-transport lost gas.
- The proposed regulations pertaining to the Type A, Area 2 gathering lines would extend the useful life of these pipelines due to the emphasis on prevention, maintenance, and ongoing monitoring.
- Minor and intangible benefits could be realized through greater clarity of regulatory requirements. Consistent definitions among various regulatory agencies, including state and federal pipeline safety agencies, would yield some benefits to operators by eliminating confusion in the interpretation of regulations, particularly for multi-state operators. Agencies responsible for oversight of gathering lines may be more efficient by reducing activities such as answering operator questions, site verification visits, and written clarifications.

7. BENEFIT-COST ANALYSIS PERTAINING TO TOPIC AREA 8 (GAS GATHERING LINES)

This section provides a comparison of benefits and costs for topic area 8 which applies to gas gathering lines. This section also addresses alternatives to the proposed rule in this topic area.

7.1 BENEFITS AND COSTS OF PROPOSED RULE

The costs associated with the proposed safety provisions and the expected safety and environmental benefits from those would apply to the approximately 69,000 miles of newly-regulated gathering lines (Table 3-65) that would be subject to select safety provisions. The costs associated with the reporting provisions would apply to those and the additional 344,000 miles of other currently unregulated gathering lines.

Table 7-1. Summary of Benefits for Topic Area 8 (Millions 2015$)[1]

Benefit	Average Annual (7%)	Total (7%)	Average Annual (3%)	Total (3%)
Safety benefits[2]	$9.7	$145.5	$12.5	$188.0
GHG emissions reductions	$1.6	$24.4	$1.6	$24.4
Total	**$11.3**	**$169.9**	**$14.2**	**$212.4**

1. Total is over 15-year study period; annual is total divided by 15 years.
2. Sum of expected incidents averted times average incident consequence (see Table E-7).

Operators of Type A Area 2 mileage will incur costs to comply with new safety requirements, while operators of all other currently unregulated pipelines will incur relatively small costs to comply with reporting requirements. These costs are summarized in Table 7-2.

Table 7-2 Summary of Compliance and Reporting Costs for Topic Area 8 (Millions 2015$)[1]

Average Annual (7%)	Total (7%)	Average Annual (3%)	Total (3%)
$12.8	$191.6	$15.3	$229.7

1. Total is over 15-year study period; annual is total divided by 15 years.

7.2 CONSIDERATION OF ALTERNATIVES FOR TOPIC AREA 8

With regard to the repealing reference to API RP-80 for defining gathering lines, PHMSA did not consider maintaining the *status quo* to be a viable alternative. The existing definition has proven to be problematic (as described in Section 3.8.A.1) and needs to be addressed. [53]

PHMSA considered an alternative to apply some degree of safety regulations to all unregulated onshore gathering line. This alternative would have applied risk-based rationale to apply selected regulations to pipelines based on a graded approach to address risks appropriate for each category of pipeline. Under this alternative, a very large amount of

[53] ORNL Report, dated Sep 4, 2013, entitled "Review of Existing Federal and State Regulations for Gas and Hazardous Liquid Gathering Lines", ORNL/TM-2013/133.

mileage, 195,000 (over 25 times more than currently regulated) would have substantial incremental compliance costs, while the incremental benefits, in the form of cost of incidents avoided, would be considerably smaller, since the additional line mileage would be smaller, lower pressure, and more rural than line mileage in the proposed rule. Therefore, this alternative is not proposed.

With regard to the proposed reporting requirements, PHMSA considered continuing to exempt the 285,000 miles of gathering lines (that it was not proposing to regulate under the safety provisions of Part 192) from the reporting requirements in Part 191. In the past, PHMSA presumed these gas gathering lines posed a lower level of risk because they are predominantly in rural locations and operated at lower stresses (<20% SMYS). PHMSA has no data with which to substantiate this presumption. In addition, the advent of shale gas production, which utilizes large diameter, high pressure gathering pipeline has invalidated this conventional approach.[54] PHMSA is aware of reports of on unregulated gathering lines, as mentioned earlier in this PRIA. Therefore, some level of reporting is deemed appropriate, especially since these lines represent an estimated 75% of the gathering line mileage in existence. This is a significant portion of the nation's gas gathering system infrastructure. Therefore, collecting a basic set of information regarding the actual safety performance of these lines would enable assessments of the nature and extent of the potential safety and environmental risks.

[54] Ibid. 45

8. EVALUATION OF UNFUNDED MANDATE ACT CONSIDERATIONS

The UMRA of 1995 requires an impact analysis for rules that that may result in the expenditure by state, local, and tribal governments, in the aggregate, or by the private sector, in exceedance of a specified threshold ($155 million annually, which is $100 million in 1995 dollars, adjusted for inflation). Topic Area 8 of the proposed rule would expand the applicability of onshore gas gathering lines subject to regulation under 49 CFR Parts 191 & 192 to include an estimated 69,000 miles of additional lines covered by select safety and reporting provisions and 344,000 miles covered only by select reporting provisions. These mileages are in Class 1 or Class 2 locations and are not currently regulated. Most of these lines are intrastate pipelines, and PHMSA conservatively assumed that these additional mileages are or would be subject to State oversight. This section provides estimates of the scope and costs of the proposed rule to the States.

There are two aspects of the proposed rule that would impact state resources necessary to provide regulatory oversight:

1) The additional mileage subject to state oversight, which would include, but not be limited to, on-site inspection and enforcement; and,
2) The addition of new operators who are not currently subject to pipeline safety regulation and now must be incorporated within state oversight programs for operator procedures and processes.

8.1 STATE INSPECTION COSTS FOR ADDITIONAL ONSHORE GAS GATHERING LINES

The onshore gas gathering lines that would be newly regulated under the proposed rule fall into two main groups for future state pipeline safety inspection workloads: 1) Type A, Area 2 lines subject to select safety and reporting provisions of PHMSA's pipeline safety regulations; and, 2) other currently unregulated onshore gathering lines subject to select reporting provisions only.

State inspectors typically inspect pipeline systems in 300 to 500-mile segments called "inspection units," however, since the proposed newly-regulated gathering lines are likely to be widely distributed geographically, PHMSA assumed that the typical new inspection unit would be half that size, or between 150- and 250-miles. PHMSA estimated that field inspection of an inspection unit from the first group of lines typically would consist of three person-days in the field, followed by two person-days of office time to document the inspection and prepare any resulting enforcement action recommendations. And, further, PHMSA estimated that each inspection unit is on a two-year cycle of inspections. For the second group, no field inspections are required as no safety provisions would apply.

8.2 STATE INSPECTION COSTS FOR FIRST-TIME OPERATORS OF REGULATED ONSHORE GAS GATHERING LINES

Pipeline operators undergo company headquarters inspections in which the state pipeline safety inspection staff examines the operator's policies, procedures, and processes

associated with compliance to pipeline safety regulations. Operators with added gathering line mileage under the proposed rule, but with pre-existing regulated lines, will have already undergone such inspections and already be in the state's routine, corporate-level inspection cycle. Operators without pre-existing regulated lines would undergo an initial company headquarters inspection, and thereafter be incorporated within the state's master list of operators subject to oversight. Again, the scope and extent of these company headquarters inspections would depend on which of the two main groups of pipelines is involved, namely, those that would be subject to the safety and reporting provisions, or those that would be subject only to the reporting provisions. For operators that have Type A, Area 2 pipelines, PHMSA estimated that a first-time company headquarters inspection would consist of five person-days on-site, plus two person-days of follow-up documentation and processing. PHMSA estimated that each new operator would be on a five-year cycle of company headquarters inspections thereafter, and assumed the initial inspections would be conducted and distributed evenly, over a period of three years.

8.3 ESTIMATED COSTS FOR STATE INSPECTIONS OF NEWLY-REGULATED GATHERING LINES SUBJECT TO SAFETY INSPECTION

Table 8-1 lists the estimated mileages of the gathering pipelines that would become newly inspected under the proposed rule, including an estimate of the number of new inspection units that would need to be created.

Table 8-1. Mileages, Inspection Units, and New Operators for the Newly-Regulated Gathering Lines

Mileage Group Descriptions	Estimate of Miles	Estimated of Inspection Units[1]
Type A, Area 2	**68,749**	**344**
Operator group 1	2,200	11
Operator group 2	66,549	333

1. Calculated as miles divided by 200.

Unit costs to the states are estimated based on the actual 2012 expenses for gas and hazardous liquid programs, as well as on the actual total number of person-days allotted within the states and reported to PHMSA in states annual reports. Table 8-2 shows these values.

Table 8-2. Unit Cost for State Pipeline Safety Programs in 2012

Total State Program Expenses	Estimated Number of Inspection-Days	Unit Cost per Inspection-Day
$50,202,484	39,473	$1,272

Source: State reports

8.3.1 FIELD INSPECTION COSTS

Routine field inspection costs are estimated to total $2.26 million, split evenly over two years for a two-year recurring inspection cycle, yielding approximately $1.13 million per year (**Table 8-3**).

Table 8-3. Estimated Routine Field Inspection Costs to the States for Newly-Regulated Gathering Lines Subject to Safety Provisions (Type A, Area 2)

Estimated Inspection Units	No. of Inspection-Days per Unit	Total Field Inspection-Days	Total Field Inspection Costs ($ / 2 years)
356	5	1,780	$2,264,160

8.3.2 HEADQUARTERS INSPECTION COSTS

Consistent with Section 3.8.2.4., the proposed rule is expected to result in newly-regulated operators. **Table 8-4** provides estimates of company headquarters inspection costs for the states for different assumptions regarding the specific number of operators. From estimates ranging from 75 to 125 newly regulated operators, estimated total annual costs would range from approximately $0.7 million to $1.1 million, distributed equally over the operators' first three years in the program ($0.2 million to $0.4 million per year), and then recur annually at the reduced rate of $0.1 million to $0.2 million per year since they then recur on a 5-year cycle..

Table 8-4. Company Headquarter Inspection Costs to the States for Newly-Regulated Operators Subject to Safety Provisions

No. of Operators	No. of Inspection-Days per Operator	Total HQ Inspection-Days	Total HQ Inspection Costs[1]	Cost per Year, Initial 3-Year Cycle[2]	Cost per Year, Recurring 5-Year Cycle[3]
75	7	525	$667,800	$222,600	$133,560
100	7	700	$890,400	$296,800	$178,080
125	7	875	$1,113,000	$371,000	$222,600

HQ = headquarters
1. Inspection-days times unit cost per day ($1,272, see Table 8-2).
2. Total divided by 3.
3. Total divided by 5.

8.3.3 TOTAL INSPECTION COSTS

Combining the costs in Table 8-3 and Table 8-4 the total estimated cost to the states for Topic Area 8 of the proposed rule would not exceed approximately $1.5 million per year (**Table 8-5**).

Table 8-5. Total Annual Costs to the States for Newly-Regulated Gathering Lines Subject to Safety Provisions, First Three Years (Millions)

Field Inspections	Company HQ Inspections[1]	Total
$1.1	$0.2 - $0.4	$1.3 - $1.5

1. Based on between 75 and 125 newly regulated operators, for example.

8.3.4 SUMMARY

Based on estimated costs to states not exceeding $1.5 million per year, under plausible assumptions regarding the number newly regulated operators, the magnitude of potential impact is significantly less than the criteria in the Act (over $155 million per year, in current year dollars).

APPENDIX A SUPPLEMENTAL CALCULATIONS FOR TOPIC AREA 1 COST ESTIMATES

This appendix shows the estimation of the impacted HCA mileage for MAOP verification provisions of Topic Area 1. Specifically it estimates the HCA mileage that operates at stresses greater than 30% of SMYS, and between 20-30% of SMYS and is certified under 49 CFR §619(c).[55] **Tables A-1** and **A-2** calculate the impacted mileage for those two populations of pipeline segments based on operators annual report submissions.

A-1. Calculation of HCA Mileage Operating at Pressure Greater than 30 Percent SMYS

Location	Onshore Gas Transmission Miles[1]	HCA Mileage[2]	Total >30% SMYS	% >30% SMYS	HCA >30% SMYS
Interstate					
Class 1	160,381	62	145,656	91%	56
Class 2	17,811	23	14,918	84%	19
Class 3	13,925	439	11,319	81%	357
Class 4	29	0	16	55%	0
Total	192,146	524	171,908	89%	469
Intrastate					
Class 1	72,254	13	56,034	78%	10
Class 2	12,820	18	9,018	70%	13
Class 3	19,726	749	11,876	60%	451
Class 4	880	5	430	49%	3
Total	105,680	786	77,358	73%	575
Total Onshore					
Class 1	232,635	75	201,690	87%	65
Class 2	30,631	41	23,936	78%	32
Class 3	33,652	1,189	23,194	69%	819
Class 4	908	6	446	49%	3
Total	297,826	1,310	249,266	84%	1,096

Source: 2014 PHMSA Annual Report
1. Part K
2. Part Q GF HCA
3. Part K

A-2. Calculation of HCA Mileage Operating at Pressure 20-30% SMYS

Location	Onshore Gas Transmission Miles[1]	HCA Mileage[2]	Total 20-30% SMYS	% >30% SMYS	HCA >30% SMYS
Interstate					
Class 1	160,381	62	7,975	5%	3
Class 2	17,811	23	1,433	8%	2
Class 3	13,925	439	1,305	9%	41

[55] Commonly referred to as the "Grandfather Clause"

A-2. Calculation of HCA Mileage Operating at Pressure 20-30% SMYS					
Location	**Onshore Gas Transmission Miles[1]**	**HCA Mileage[2]**	**Total 20-30% SMYS**	**% >30% SMYS**	**HCA >30% SMYS**
Class 4	29	0	9	32%	0
Total	192,146	524	10,722	6%	46
Intrastate					
Class 1	72,254	13	8,245	11%	1
Class 2	12,820	18	2,737	21%	4
Class 3	19,726	749	5,610	28%	213
Class 4	880	5	427	49%	3
Total	105,680	786	17,019	16%	221
Total Onshore					
Class 1	232,635	75	16,220	7%	5
Class 2	30,631	41	4,170	14%	6
Class 3	33,652	1,189	6,914	21%	254
Class 4	908	6	436	48%	3
Total	297,826	1,310	27,740	9%	267
Source: 2014 PHMSA Annual Report. 1. Part K 2. Part Q GF HCA 3. Part K					

APPENDIX B SOCIAL COST OF GREENHOUSE GAS EMISSIONS

This appendix provides estimates of the social cost of carbon (SCC) and methane (SCM). In this analysis, PHMSA uses these values to estimate costs associated these greenhouse gas (GHG) emissions from the blowdown of gas during compliance activities (primarily methane) and released as a result of incidents [which may also include carbon dioxide (CO_2) if the gas ignites].

The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year [Interagency Working Group (IWG), 2015].[56] The IWG on SCC developed estimates of these damages to allow agencies to incorporate the social benefits of reducing carbon dioxide (CO_2) emissions into cost-benefit analyses of regulatory actions that impact cumulative global emissions. The estimates include, but are not limited to, changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change. IWG (2015) calculates the SCC using discount rates of 2.5%, 3%, and 5%. **Table B-1** shows the SCC each year, which is applied to emission changes for the relevant years to estimate the dollar value of GHG impacts from CO_2 emissions.

Marten et al. (2014)[57] used the same models and assumptions that underlie the current IWG SCC estimates (IWG 2013; updated 2015) to develop a unit SCM [see EPA (no date)[58] for detailed discussion of the limitations of using the global warming potential (GWP) approach previously used by some federal agencies to monetize the costs of methane releases for inclusion in benefit-cost analyses].[59] **Table B-2** shows the SCM based on Marten et al., (2014).

Tables B-3 through **B-5** provide the estimated social costs and benefits of the proposed rule due to changes in GHG emissions. Note that Table B-3 and B-4 only illustrate the low

[56] Interagency Working Group on Social Cost of Carbon (IWG), United States Government. 2015. Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. Revised July 2015.
[57] Marten, A.L., E.A. Kopits, C.W. Griffiths, S.C. Newbold, and A. Wolverton. 2014. Incremental CH4 and N20 Mitigation Benefits Consistent with the US Government's SC-CO2 Estimates. Climate Policy.
[58] U.S. Environmental Protection Agency (EPA). No date. Whitepaper on Valuing Methane Emissions Changes in Regulatory Benefit-Cost Analysis, Peer Review Charge Questions, and Responses. http://www3.epa.gov/climatechange/pdfs/social%20cost%20methane%20white%20paper%20application%20and%20peer%20review.pdf
[59] In brief, a potential method for approximating the SCM is to convert the units of methane to units of CO_2-equivalent using the GWP, then applying the SCC. However, methane is more potent but has a much shorter life than CO2, resulting in more impacts in the near term, which would be discounted less heavily than impacts occurring further out in the future. Additionally, methane does not have the positive fertilization impacts that CO2 does. Several recent studies found that GWP-weighted benefit estimates for methane are likely to be lower than the estimates derived using directly modeled social cost estimates for these gases. Gas comparison metrics, such as the GWP, are designed to measure the impact of non-CO_2 GHG emissions relative to CO_2 at a specific point along the pathway from emissions to monetized damages and this point may differ across measures. Because these and other variations in the timing and nature of impacts are not captured by simply multiplying the SCC by GWP, IWG (2010) recommends against using this approach to value non-CO_2 GHG.

Interagency Working Group on Social Cost of Carbon (IWG), United States Government. 2010. Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.

incidents averted scenario for Topic Area 1.

Table B-1. Social Cost of Carbon Based on IWG (2015)[1]

Year	SCC (per metric ton CO2; 2007$)	SCC (per metric ton CO2; 2015$)
2015	$36	$41
2016	$38	$43
2017	$39	$45
2018	$40	$46
2019	$41	$47
2020	$42	$48
2021	$42	$48
2022	$43	$49
2023	$44	$50
2024	$45	$51
2025	$46	$53
2026	$47	$54
2027	$48	$55
2028	$49	$56
2029	$49	$56
2030	$50	$57

Source:
1. Based on 3% discount rate.
CO_2 = carbon dioxide
IWG = The Interagency Working Group on Social Cost of Carbon
SCC = social cost of carbon

Table B-2. Social Cost of Methane Based on Marten et al., (2014)

Year	SC per metric ton methane (2007$)	SC per MCF methane (2015$)
2015	$1,100	$24
2016	$1,120	$25
2017	$1,140	$25
2018	$1,160	$26
2019	$1,180	$26
2020	$1,200	$26
2021	$1,240	$27
2022	$1,280	$28
2023	$1,320	$29
2024	$1,360	$30
2025	$1,400	$31
2026	$1,440	$32
2027	$1,480	$33
2028	$1,520	$34

Table B-2. Social Cost of Methane Based on Marten et al., (2014)		
Year	**SC per metric ton methane (2007$)**	**SC per MCF methane (2015$)**
2029	$1,560	$34
2030	$1,600	$35

Source: Marten, A.L., E.A. Kopits, C.W. Griffiths, S.C. Newbold, and A. Wolverton. 2014. Incremental CH_4 and N_20 Mitigation Benefits Consistent with the US Government's SC-CO_2 Estimates. Climate Policy. Inflated to 2015 based on 2015 average CPI of 237.0
SC = Social cost
MCF = 1,000 ft^3 of a gas at standard temperature and pressure

Table B-3. Total Social Cost of GHG Emissions due to Pressure Test and ILI Upgrade related Blowdowns (3%)

Year	Methane Emissions (MCF)	SCM (3%)	CO_2 Emissions (lbs)	CO_2 Emissions (metric tons)	SCC	Social Cost of GHG Emissions
2016	65,012	$1,606,424	96,686	44	$1,667	$1,608,090
2017	65,012	$1,635,110	96,686	44	$1,710	$1,636,820
2018	65,012	$1,663,796	96,686	44	$1,754	$1,665,550
2019	65,012	$1,692,482	96,686	44	$1,798	$1,694,280
2020	65,012	$1,721,168	96,686	44	$1,842	$1,723,010
2021	65,012	$1,778,540	96,686	44	$1,842	$1,780,382
2022	65,012	$1,835,913	96,686	44	$1,886	$1,837,798
2023	65,012	$1,893,285	96,686	44	$1,930	$1,895,215
2024	65,012	$1,950,657	96,686	44	$1,974	$1,952,631
2025	65,012	$2,008,029	96,686	44	$2,017	$2,010,047
2026	65,012	$2,065,402	96,686	44	$2,061	$2,067,463
2027	65,012	$2,122,774	96,686	44	$2,105	$2,124,879
2028	65,012	$2,180,146	96,686	44	$2,149	$2,182,295
2029	65,012	$2,237,518	96,686	44	$2,149	$2,239,667
2030	65,012	$2,294,891	96,686	44	$2,193	$2,297,084
Total	975,180	$28,686,134	1,450,287	658	$29,076	$28,715,211

CO_2 = carbon dioxide
GHG = greenhouse gas
lbs = pounds
MCF = thousand cubic feet
MT = metric ton
SCC = social cost of carbon
SCM = social cost of methane

Table B-4. Social Benefit of GHG Emissions Reductions, Topic Areas 1-7, Discounted at 3% (2015$)

Year	Methane Emissions (MCF)	SCM (3%)	CO_2 Emissions (lbs)	CO_2 Emissions (MT)	SCC	GHG Reduction Benefit
2016	256,006	$6,325,820	1,926,905	874	$33,213	$6,359,033
2017	256,006	$6,438,781	1,926,905	874	$34,087	$6,472,868
2018	256,006	$6,551,742	1,926,905	874	$34,961	$6,586,703
2019	256,006	$6,664,703	1,926,905	874	$35,835	$6,700,538
2020	256,006	$6,777,664	1,926,905	874	$36,709	$6,814,373
2021	256,006	$7,003,587	1,926,905	874	$36,709	$7,040,296
2022	256,006	$7,229,509	1,926,905	874	$37,583	$7,267,092
2023	256,006	$7,455,431	1,926,905	874	$38,457	$7,493,888
2024	256,006	$7,681,353	1,926,905	874	$39,331	$7,720,684
2025	256,006	$7,907,275	1,926,905	874	$40,205	$7,947,480
2026	256,006	$8,133,197	1,926,905	874	$41,079	$8,174,276
2027	256,006	$8,359,119	1,926,905	874	$41,953	$8,401,073
2028	256,006	$8,585,042	1,926,905	874	$42,827	$8,627,869
2029	256,006	$8,810,964	1,926,905	874	$42,827	$8,853,791
2030	256,006	$9,036,886	1,926,905	874	$43,701	$9,080,587
Total	3,840,090	$112,961,073	28,903,579	13,110	$579,479	$113,540,552

CO_2 = carbon dioxide
GHG = greenhouse gas
lbs = pounds
MCF = thousand cubic feet
MT = metric ton
SCC = social cost of carbon
SCM = social cost of methane

Table B-5. Social Benefits of Avoided Gathering Line GHG Emissions (3%)						
Year	Avoided CH_4 emissions (MCF)	SCM (3%)	Avoided C02 Emissions(lbs)	C02 Emissions (MT)	SCC	Social Cost of GHG Emissions
2016	26,746	$660,888	101,992	46	$1,758	$662,646
2017	47,480	$1,194,154	181,055	82	$3,203	$1,197,357
2018	47,480	$1,215,104	181,055	82	$3,285	$1,218,389
2019	47,480	$1,236,054	181,055	82	$3,367	$1,239,421
2020	47,480	$1,257,004	181,055	82	$3,449	$1,260,453
2021	59,920	$1,639,229	228,494	104	$4,353	$1,643,582
2022	59,920	$1,692,107	228,494	104	$4,457	$1,696,564
2023	59,920	$1,744,985	228,494	104	$4,560	$1,749,546
2024	59,920	$1,797,864	228,494	104	$4,664	$1,802,528
2025	59,920	$1,850,742	228,494	104	$4,768	$1,855,510
2026	59,920	$1,903,620	228,494	104	$4,871	$1,908,492
2027	59,920	$1,956,499	228,494	104	$4,975	$1,961,474
2028	59,920	$2,009,377	228,494	104	$5,078	$2,014,456
2029	59,920	$2,062,255	228,494	104	$5,078	$2,067,334
2030	59,920	$2,115,134	228,494	104	$5,182	$2,120,316
Total	815,861	$24,335,016	3,111,149	1,411	$63,049	$24,398,065

CH_4 = methane
CO_2 = carbon dioxide
GHG = greenhouse gas
lbs = pounds
MCF = thousand cubic feet
MT = metric ton
SCC = social cost of carbon
SCM = social cost of methane

APPENDIX C RATE OF INCIDENT PREVENTION AS A FUNCTION OF ASSESSMENT MILEAGE

PHMSA estimated benefits for Topic Area 1 as the number of miles assessed times the rates that defects are detected and the proportion of those defects which would evolve into pipe failures if they are not repaired. This appendix shows the estimation of the defect discovery rate per mile based on historical integrity assessment performance data reported in gas transmission and hazardous liquid annual reports.

C.1 PREVENTION OF INCIDENTS BY IN-LINE INSPECTION

The cost and benefit analysis for topic area 1 is based in part on an estimate of the number of defects that would be discovered and remediated (repaired) as a result of the integrity assessments required by the proposed rule. There are two baselines that apply, depending on the type of pipelines segments to which a given topic area applies. (1) Pipe that has not been previously assessed and remediated in accordance with integrity management requirements (Subpart O of Part 192). This would predominantly include pipe located in the proposed MCA in Class 1 and 2 locations. (2) Pipe that has been previously assessed and remediated in accordance with integrity management requirements (Subpart O of Part 192). This would include pipe in HCAs and most class 3 and 4 pipe in proximity to HCAs that would reasonably be expected to have been assessed in conjunctions with HCA assessments.

Existing requirements for gas operators do not include all of the proposed repair criteria. However, the hazardous liquid (HL) pipeline IM rule has always included many (but not all) of the proposed repair criteria. Because the existing HL repair criteria are similar to the proposed gas repair criteria, and PHMSA has reliable data from HL operators for reported repairs, the HL repair data can be used as a proxy for an expected defect discovery rate for GT pipelines under the proposed rule. Causes of GT pipeline accidents and the vulnerability of pipelines to threats and deleterious environments are very similar to HL pipelines. For the purpose of this analysis, it is reasonable to apply the HL repair data to GT pipelines that have not been previously assessed.

However, some pipelines that would require an assessment under the proposed rules have already been assessed because they are located in an HCA. To account for the defects previously discovered and remediated under Part 192, Subpart O, PHMSA used the difference between the HL discovery rate and the GT historical discovery rate. In making this comparison, PHMSA used data from 2004-2009 because the baseline assessment periods for both HL and GT IM programs overlapped during these years and data is more directly comparable.

PHMSA used an annual average of each of the defect discovery rates used in the analysis. As shown in the tables below, mileage assessed has generally trended down while the rates at which defects are discovered have gone up. The latter is not unexpected since PHMSA expects that both integrity assessment accuracy and defects due to metal fatigue or corrosion may increase over time. The annual average retains earlier data while giving more weight to more recent years. This method likely more accurately estimates current and future performance of integrity assessment technologies.

Table 4-1 in the body of the report summarizes the defect discovery rates used in this

analysis. PHMSA applied an average of the historical hazardous liquid defect discovery rates between 2004 and 2009 as an estimate of the discovery rate on non-HCA pipelines which have not previously been assessed (including MCA). These rates are 0.10 immediate repair conditions per mile 0.10 per mile and 0.49 scheduled repair conditions per mile. For HCA segments assessed PHMSA applied the average difference between the hazardous liquid defect discovery rate and the gas transmission discovery rate over the same period. This reflects the marginal change due to the difference in repair and assessment criteria. For HCA assessment miles these rates are 0.05 immediate repair conditions per mile and 0.38 scheduled repair conditions per mile.

The number of incidents averted is estimated by the conditions that are discovered and repaired. As stated in ASME B31.8S, Section 7.2, immediate conditions are those that indicate the defect is at the failure point, with little, if any, safety margin remaining. Immediate conditions could be discovered through assessments using ILI or direct assessment. Even though immediate conditions represent defects in the pipe that are at the failure point, experience has shown that not all of those defects would fail before the next integrity assessment. For purposes of this analysis, PHMSA assumed that between 3.0%-12.5% of the immediate conditions discovered and repaired represent incidents averted.

Conditions requiring one-year and scheduled repairs occur at a higher rate than immediate conditions. Even though these conditions do not meet the criteria for an immediate repair, they do reduce the strength of the pipe and make the pipe more susceptible to failure, especially in the presence of other interacting defects or threats (such as external force, third-party damage, or repeated pressure fluctuations). There have been cases where defects that did not meet the immediate repair criteria have failed in service before the defect was repaired. However, those are less likely than an immediate condition to lead to failure before the next integrity assessment. In the absence of specific data, for purposes of this analysis, PHMSA assumed that between 0.3%-0.5% of non-immediate conditions discovered and repaired represent incidents averted.

Using the data in **Table C-1** and **Table C-2**, and the above assumptions, PHMSA estimated the rate of incidents averted (prevented) by the discovery and repair of immediate conditions and scheduled conditions for both previously assessed and previously unassessed segments, shown in the figures below. For HCA pipe, PHMSA used the incident prevention rate for previously assessed pipe. For non-HCA and MCA pipe, PHMSA used the defect discovery rate for previously unassessed pipe.

Table C-1. Estimated Immediate Condition Repair Rates for Previously Unassessed Pipe and Previously Assessed Pipe

Year	Hazardous Liquid Integrity Management Immediate Repair Rate			Gas Transmission Integrity Management Immediate Repair Rate			GT Estimated Immediate Repair Rate for Previously Assessed Pipe
	Total HL Assessment Miles	HL HCA Immediate Repairs	HL Immediate Repair Rate[1]	Total GT Assessment Miles	GT HCA Immediate Repairs	GT HCA Immediate Repair Rate	
2004	65,565	1,701	0.026	3998	104	0.026	0.000
2005	17,501	1,369	0.078	2906	261	0.090	-0.012
2006	12,411	941	0.076	3500	158	0.045	0.031
2007	9,240	880	0.095	4663	258	0.055	0.040

Table C-1. Estimated Immediate Condition Repair Rates for Previously Unassessed Pipe and Previously Assessed Pipe

Year	Hazardous Liquid Integrity Management Immediate Repair Rate			Gas Transmission Integrity Management Immediate Repair Rate			GT Estimated Immediate Repair Rate for Previously Assessed Pipe
	Total HL Assessment Miles	HL HCA Immediate Repairs	HL Immediate Repair Rate[1]	Total GT Assessment Miles	GT HCA Immediate Repairs	GT HCA Immediate Repair Rate	
2008	5,916	888	0.150	2858	181	0.063	0.087
2009	3,372	660	0.196	3288	144	0.044	0.152
Average rate[2]	NA	NA	**0.104**	NA	NA	0.054	**0.050**

Source: Gas Transmission and Hazardous Liquid Annual Reports
GT = gas transmission
HCA = high consequence area
HL = hazardous liquid
NA = not applicable
1. Assumed gas transmission repair rate for previously unassessed pipe.
2. Average of 2004-2009 rates

Table C-2. Estimated Scheduled Condition Repair Rates for Previously Unassessed Pipe and Previously Assessed Pipe

Year	Hazardous Liquid Integrity Management Scheduled Condition Repair Rate						Gas Transmission Integrity Management Scheduled Repair Rate			GT Estimated Scheduled Repair Rate for Previously Assessed Pipe
	Total HL Assessed Miles	HL HCA 60-Day Repairs	HL 60-day Repair Rate	HL HCA 180-day Repairs	HL 180-day Repair Rate	HL Total HCA Scheduled Repair Rate[1]	Total Assessed Miles	Total Scheduled Repairs	Scheduled Repair Rate	
2004	65565	647	0.0099	3178	0.0485	0.058	3,998	599	0.150	-0.091
2005	17501	1109	0.0634	5278	0.3016	0.365	2,907	378	0.130	0.235
2006	12411	861	0.0694	2748	0.2214	0.291	3,501	344	0.098	0.193
2007	9240	580	0.0628	2139	0.2315	0.294	4,663	452	0.097	0.197
2008	5916	1022	0.1728	4037	0.6824	0.855	2,858	252	0.088	0.767
2009	3372	454	0.1346	3088	0.9158	1.050	3,288	266	0.081	0.970
Avg. rate[2]	NA	NA	0.0855	NA	0.400	**0.486**	NA	NA	0.107	**0.378**

Source: Gas Transmission and Hazardous Liquid Annual Reports
GT = gas transmission
HCA = high consequence area
HL = hazardous liquid
NA = not applicable
1. Assumed gas transmission repair rate for previously unassessed pipe.
2. Average of 2004-2009 rates

C.2 PREVENTION OF INCIDENTS BY PRESSURE TESTING

Table C-3 shows annual report data for 2010- 2013.

Table C-3. Pressure Test Failures 2010-2013			
Year [1]	Miles Pressure Tested	Failures both in and out HCA	Test Failure Rate per Mile
2013	1,502	54	0.0360
2012	2,078	52	0.0250
2011	1,687	71	0.0421
2010	1,393	51	0.0366
Average Rate[2]	NA	NA	0.0349

1. Operators were not required to report pressure test failures prior to 2010.
2. Average of 2010-2013 rates

Table C-3 indicates an average annual rate of 0.0349 test failures/mile, with a mean/standard deviation ratio of 4.9. PHMSA applied this discovery rate for both previously assessed HCA miles and previously unassessed non-HCA miles For purposes of this analysis, PHMSA assumes that between one out of 3 (33%) and one half (50%) of historical pressure test failures represent incidents averted.

APPENDIX D CONSEQUENCES OF SAN BRUNO INCIDENT

The CPUC proposed a $1.4B fine[60] and the Department of Justice filed an indictment,[61] in which PGE is alleged to have violated numerous integrity management regulations (49 CFR Part 192, Subpart O). PHMSA is proposing to provide greater emphasis on those regulations through the proposed changes in Topic Area 2. Those proposed regulatory provisions are not changes to existing requirements, thus neither costs nor benefits are estimated for those proposals. However, many of the issues being addressed by the proposed regulations in Topic Areas 1 and 3 are new requirements designed to address the lessons learned, causes, and contributing factors to the San Bruno incident of September 9, 2010. Those major causes and contributing factors, as identified by NTSB, related to the proposed regulations in topic area 1 are summarized as follows:

1. "The National Transportation Safety Board determines that the probable cause of the incident was the Pacific Gas and Electric Company's (PG&E) (1) inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, which allowed the installation of a substandard and poorly welded pipe section with a visible seam weld flaw that, over time grew to a critical size, causing the pipeline to rupture during a pressure increase stemming from poorly planned electrical work at the Milpitas Terminal …" ─ NTSB

   The Management of Change regulations proposed in Topic Area 3 are designed to address the process for change control to prevent unauthorized material substitutions such as the substandard pipe section installed in 1956 and the poorly planned electrical work at Milpitas Terminal. The proposed integrity verification requirements in Topic Area 1 are designed to find and fix substandard pipe segments such as were discovered to have failed at San Bruno, including requirements for establishing material properties and related records.

2. "Contributing to the incident were the California Public Utilities Commission's (CPUC) and the U.S. Department of Transportation's exemptions of existing pipelines from the regulatory requirement for pressure testing, which likely would have detected the installation defects." ─ NTSB

The proposed regulations in Topic Area 1 include repeal of exemptions for pressure testing for pipe in HCAs or MCAs, and the conduct of assessments or other measures by which operators must verify the MAOP of the pipeline segment for which pressure testing was previously exempt, including requirements for establishing material properties and related records.

The NTSB issued numerous specific recommendations to address the causes and contributing factors of the San Bruno incident. PHMSA described those NTSB recommendations and how they influenced the scope of the proposed rule in Sections 1, 2, and 3.

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[60] California Public Utilities Commission, Press Release, September 2, 2014, "CPUC JUDGES ISSUE DECISIONS IN PG&E PIPELINE CASES, LEVYING LARGEST SAFETY RELATED PENALTY EVER BY CPUC"
[61] http://oag.ca.gov/news/press-releases/attorney-general-kamala-d-harris-issues-statement-federal-indictment-pge

PHMSA incident data includes the number of fatalities and serious injuries (that require overnight hospitalization), and the value of property damaged as a result of the incident (such as cost to repair or replace homes damaged, damage to the operator's property, etc.). Also included are other consequences, including the operator's costs associated with responding to the emergency, the cost of gas lost, number of persons evacuated, and the duration of system shutdown. PG&E, in its final incident report for the San Bruno incident, reported 8 fatalities, 51 injuries, and no evacuations, along with $100,000 in property damage, $0 cost for emergency response, $263,000 in the cost of lost gas, and $375M in other damages.

However, operators are not required to include in incident reports all consequence costs, such as the cost of public safety and first responders, cost of evacuation, lawsuit judgments/settlements, legal fees, cost of repair to public infrastructure, cost of investigation, evaluation of other pipeline segments, cost of implementing orders from regulatory agencies in response to the incident, lost productivity, lost revenue, and other extraordinary costs attributable to the incident, many of which are not legally settled or finalized until years after the incident. Such costs are often difficult to discover, since settlement information is sometimes not disclosed, but may be incurred nonetheless. However, in the case of severe incidents with intense media coverage, additional consequential cost data is often discoverable, especially if the operator is a publically traded company. If known, with a reasonable degree of certainty, such information can be used to more accurately estimate and monetize the consequences of a given incident. Relying solely on PHMSA incident report data would understate the true consequential costs of severe incidents. For example, in the case of the San Bruno incident, the Dow Jones Newswire[62] reported that, as of February 21, 2013, the cost incurred by PG&E as a result of the San Bruno incident exceeded $1.9B and was estimated to total approximately $3B. This information is reflected in PG&E annual reports, which itemize the unrecoverable costs PG&E charged for the San Bruno incident beginning in 2010. The cumulative costs through 2013 total $2.594B (excluding fines and penalties). PG&E was expected to continue to pay additional costs in 2014, as explicitly reported in the company's 2013 annual report, and in subsequent years in accordance with its CPUC mandated Pipeline Safety Enhancement Plan.

Accordingly, PHMSA estimated the consequences of the San Bruno incident as follows.

1. **Loss of life, injuries, and property damage to the public.** Most of the lawsuits from individuals harmed by the incident have been settled. As reported by PG&E in its annual reports for 2010,[63] 2011,[64] 2012,[65] and 2013,[66] PG&E charged a total of $565M for those settlements. Subtracting the value of statistical life for 8 deaths and 51 injuries, results in an estimate of other damages to those individuals harmed by the incident of approximately $508M.
2. **Cost of gas lost.** PG&E's incident report stated that the value of gas lost as a result

[62] Dow Jones Newswires, PG&E Faces Continued Costs, Uncertainty After San Bruno Pipeline Blast, February 21, 2013, 15:07ET; http://www.nasdaq.com/aspx/stockmarketnewsstoryprint.aspx?storyid=pge-faces-continued-costs-uncertainty-after-san-bruno-pipeline-blast-20130221-01304
[63] PG&E Corporation and Pacific Gas and Electric Company, 2010 Annual Report
[64] PG&E Corporation and Pacific Gas and Electric Company, 2011 Annual Report
[65] PG&E Corporation and Pacific Gas and Electric Company, 2012 Annual Report
[66] PG&E Corporation and Pacific Gas and Electric Company, 2013 Annual Report

of the incident was $263,000.

3. **Emergency response (PG&E).** Although PG&E did not report any costs for emergency response, it deployed SCADA center crews, dispatched staff to the scene, deployed onsite crews and field supervisors, activated the San Carlos operations emergency center command post, and activated its San Francisco headquarters operations emergency center command post. PHMSA estimated the cost of PG&E emergency response for the San Bruno incident to be approximately $250,000.

4. **Emergency response (government and public) and post-incident recovery.** Operators are not required to report the government and public response to the incident. However, reliable reports[67] and studies[68] identified that approximately 600 firefighters, 325 law enforcement, 90 ground apparatus, 4 air tankers,[69] 2 air attack planes, and 1 helicopter, responded to the incident within the first 50 hours. PG&E funded a $50M trust for the City of San Bruno[70] explicitly to cover any costs directly related to the fire response and the cost of recovery. The trust also provides funds for infrastructure repair and replacement, additional government and responder staffing costs, costs of participation in regulatory proceedings, and the costs of legal and other experts as needed.

5. **Disaster relief.** As reported by PG&E in its 2010 annual report (p. 11), "PGE [PG&E] provided $63 million of costs incurred to provide immediate support to the San Bruno community, re-inspect the Utility's natural gas transmission lines, and to perform other activities following the incident." Most of these disbursements were direct disbursements to affected parties immediately after the incident in the form of checks, gift cards, emergency assistance, charitable contributions, natural gas bill relief, and miscellaneous emergency support (e.g., PG&E community support webpage). In addition, the American Red Cross, provided $1,587,210 in disaster relief[71] and the Glenview Fire Relief Fund provided $400,000 in disaster relief.[72]

6. **Evacuations.** PG&E reported no evacuations as a result of the incident, but NTSB Pipeline Incident Report PAR-11-01 identified that 300 houses were evacuated. PHMSA considers these evacuation costs to be included in the disaster relief item above.

7. **Consequences of system shutdown and mandatory operating pressure reduction (Urgent NTSB Recommendation P10-5/CPUC Order R L-403).** The California Public Utilities Commission (CPUC) ordered PG&E to impose a mandatory pressure reduction on several of its pipeline systems, in the wake of the San Bruno incident, and required that PG&E obtain CPUC approval before increasing pressure.[73] NTSB

[67] National Transportation Safety Board, Pipeline Incident Report, Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010, NTSB/PAR-11/01
[68] University of Delaware Disaster Research Center, Report on San Bruno Disaster, Final Project Report #56, 2012.
[69] California Fire News (blog). September 9, 2010
[70] Irrevocable Trust Agreement Dated March 24, 2011, http://www.sanbruno.ca.gov/Glenview_crestmoortrust.html
[71] American Red Cross, San Bruno Explosion Response, Summary Report November 2013.
[72] *Ibid*. 53
[73] Letter from Paul Clannon, Executive Director, California Public Utilities Commission to Christopher Johns, President, Pacific Gas and Electric Company, dated September 13, 2010, "Safety Response to the San Bruno Pipeline Explosion"

also issues an urgent recommendation that CPUC provide oversight to PG&E while PG&E performed records search and analysis to verify or determine the safe MAOP for its pipelines. As a result, a portion of PG&E's Line 132 between San Andreas Station and Healy Station was filled with concrete and abandoned in place. The remainder of Line 132, as well as Line 109, continue to operate at 20% pressure reduction (this restriction has been in place for 1462 days as of 12/17/2014). The pressure reduction for Lines 101, 132A, and 147 was in force for 368 days.[74] The pressure reduction for Lines 300A and 300B was in force for 294 days.[75] PHMSA lacks sufficient data or information to estimate and monetize the consequences of these operating restrictions. PG&E's system has crossties to enable continued gas supply to customers. Therefore, the impact of any reduction in capacity, if there was any, is difficult to estimate. However, the potential lost revenue and operational inefficiency resulting from the system operating restrictions could be significant.

This is conservative since PG&E costs incurred after December 31, 2013 are excluded. In its 2013 Annual Report, PG&E anticipated future unrecoverable costs associated with the San Bruno incident. These costs, $70 million of operator settlements to the City of San Bruno[76] (a transfer payment) and other unquantified costs were excluded from PHMSA's estimate of the total consequences of the San Bruno incident.

Table D-1 provides a summary of these estimates.

Table D-1. Summary of Consequences Associated with the 2010 San Bruno Pipeline Incident

Consequence	Value	Source
Deaths, injuries, and property damage	$565,000,000	PG&E Annual Reports
Cost of gas lost	$263,000	PG&E Incident Report
Emergency response (PG&E)	$250,000	NTSB Report, PHMSA estimate
Emergency response (public)	$50,000,000	NTSB Report, University of Delaware, PG&E Annual Reports
Disaster relief and evacuations	$64,987,210	PG&E Annual Reports, University of Delaware, American Red Cross
Mandatory pressure reduction	Not quantified	California Public Utilities Commission
Total	$680,500,210	See above

[74] California Public Utilities Commission, Press Release, December 15, 2011, http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/155625.htm
[75] California Public Utilities Commission, Press Release, October 6, 2011, http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/144858.htm
[76] *Ibid*., 50, pp. 14, 24

APPENDIX E CONSEQUENCES OF HISTORICAL INCIDENTS

Benefits for Topic Areas 1, 2, 3, 4, and 5 are based on preventing future incidents. In order to value the benefit of preventing future incidents, PHMSA used data from past incidents to estimate the "cost avoided" of preventing future incidents. PHMSA used data from incident reports submitted by operators for fatalities, injuries, other reported costs (which include operator property damage, other property damage, value of gas lost, and any other costs reported by the operator), and number of persons evacuated. PHMSA supplemented this data using publically available information (such as NTSB investigation reports) for selected incidents such as the San Bruno, California (see Appendix D) and Sissonville, West Virginia incidents.

For each topic area, PHMSA used a subset of the total incident filtered to only include incidents that could have reasonably be expected to have been avoided had the proposed rule requirements addressed by that topic area been in effect at the time. **Tables E-1** to **E-9** provide a summary for each subset of incident consequences used in this analysis. For comparison, Table E-1 provides incident data for gas transmission incidents for all causes is summarized in Table E-1. These tables exclude all reported operator property damage and repair costs (because they report these together) which results in understating incident costs since some of these costs (operator property damage, higher costs due to immediate need for the repair or replacement) would not be incurred with planned repair or replacement.

Regarding Table E-2, PHMSA incident data identifies the cause attributable to an incident. Some incidents might not be averted by integrity assessments and the management of time-dependent threats. Incidents due to hurricanes or other extreme weather events, or third-party damage incidents, where the pipe fails at the time of the damage would not necessarily be averted by the requirements in the proposed rule under Topic Area 1. Table E-3 summarizes the subset of gas transmission incidents that are attributable to the causes identified in Section 4.1. (Note that the list of causes was revised in 2010.) The data summarized in Table E-2 was reported to PHMSA in operator incident reports; except that publicly available information was used to estimate the consequences of the 2010 San Bruno incident (see Appendix D of this RIA).

Regarding Table E-4, note that there is no data that directly identifies whether historical incidents occurred in locations that would meet the definition of MCA under the proposed rule. PHMSA used the following two-phase approach to develop Table E-4 as a proxy for historical incidents with applicable cause codes associated with Topic Area 1 that would be located in an MCA:

1. PHMSA filtered the incidents that comprise Table E-2 to exclude HCAs and any incident that did not result in a death, reportable injury, or property damage (not owned by operator) under the premise that the lack of external consequences is likely indicative of few or no damage receptors within the PIR.
2. Of the incidents filtered out based on zero damage, PHMSA reviewed publicly available aerial photography and online mapping applications of the incident location. If it appeared as if the incident location was in proximity to five houses or a site that appeared as if it could be an occupied site, then PHMSA added those

incidents (34) to the subset of incidents that represent a proxy for MCA incidents.

Table E-1. Historical Consequences of Onshore Gas Transmission Incidents Due to All Causes (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuation[4]	Total Cost of Incidents	Average Cost per Incident
2003	81	1	$9,400,000	8	$7,896,000	$26,002,183	439	$658,500	$43,956,683	$542,675
2004	83	0	$0	2	$1,974,000	$4,027,541	1,036	$1,554,000	$7,555,541	$91,031
2005	106	0	$0	5	$4,935,000	$110,676,449	1,996	$2,994,000	$118,605,449	$1,118,919
2006	108	3	$28,200,000	3	$2,961,000	$8,419,432	995	$1,492,500	$41,072,932	$380,305
2007	86	2	$18,800,000	7	$6,909,000	$14,434,410	1,174	$1,761,000	$41,904,410	$487,261
2008	93	0	$0	5	$4,935,000	$12,154,890	635	$952,500	$18,042,390	$194,004
2009	92	0	$0	11	$10,857,000	$7,767,011	727	$1,090,500	$19,714,511	$214,288
2010	82	10	$94,000,000	61	$60,207,000	$418,615,646	265	$397,500	$573,220,146	$6,990,490
2011	101	0	$0	1	$987,000	$22,200,196	870	$1,305,000	$24,492,196	$242,497
2012	87	0	$0	7	$6,909,000	$13,710,727	904	$1,356,000	$21,975,727	$252,595
2013	93	0	$0	2	$1,974,000	$13,876,259	3,103	$4,654,500	$20,504,759	$220,481
2014	116	1	$9,400,000	1	$987,000	$14,867,441	1,445	$2,167,500	$27,421,941	$236,396
2015	117	6	$56,400,000	14	$13,818,000	$11,885,205	503	$754,500	$82,857,705	$708,186
Total	1,245	23	$216,200,000	127	$125,349,000	$678,637,389	14,092	$21,138,000	$1,041,324,389	$836,405

VSL = value of statistical life
Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files
1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-2. Historical Consequences of Onshore Gas Transmission Incidents due to Causes Detectable by Modern Integrity Assessment Methods[1] (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[2]	Number of Injuries	VSL Serious Injury[3]	Other Costs of Accident[4]	Number of Persons Evacuated	Estimated Cost of Evacuation[5]	Total Cost of Incidents	Average Cost per Incident
2003	33	0	$0	0	$0	$15,854,155	171	$256,500	$16,110,655	$488,202
2004	26	0	$0	0	$0	$1,108,283	229	$343,500	$1,451,783	$55,838
2005	27	0	$0	0	$0	$105,697,938	384	$576,000	$106,273,938	$3,936,072
2006	44	0	$0	0	$0	$2,802,314	52	$78,000	$2,880,314	$65,462
2007	38	1	$9,400,000	3	$2,961,000	$11,941,122	263	$394,500	$21,735,622	$571,990
2008	30	0	$0	1	$987,000	$8,200,877	331	$496,500	$8,697,377	$289,913
2009	32	0	$0	3	$2,961,000	$2,494,681	278	$417,000	$2,911,681	$90,990
2010	28	8	$75,200,000	51	$50,337,000	$412,056,506	29	$43,500	$487,300,006	$17,403,572
2011	29	0	$0	0	$0	$8,020,221	66	$99,000	$8,119,221	$279,973
2012	26	0	$0	0	$0	$7,585,658	524	$786,000	$8,371,658	$321,987
2013	27	0	$0	2	$1,974,000	$8,124,268	451	$676,500	$8,800,768	$325,954
2014	31	0	$0	0	$0	$5,359,479	598	$897,000	$6,256,479	$201,822
2015	28	0	$0	0	$0	$3,961,837	366	$549,000	$4,510,837	$161,101
Total	399	9	$84,600,000	60	$59,220,000	$593,207,339	3,742	$5,613,000	$683,420,339	$1,712,833

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Inline inspection, pressure testing, direct assessment, and other technology.
2. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
3. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
4. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
5. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-3. Historical Consequences of Gas Transmission Incidents due to Causes Detectable by Modern Integrity Assessment Methods[1] Located in HCAs (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[2]	Number of Injuries	VSL Serious Injury[3]	Other Costs of Accident[4]	Number of Persons Evacuated	Estimated Cost of Evacuation[5]	Total Cost of Incidents	Average Cost per Incident
2003	2	0	$0	0	$0	$3,065,772	0	$0	$3,065,772	$1,532,886
2004	3	0	$0	0	$0	$90,612	28	$42,000	$132,612	$44,204
2005	1	0	$0	0	$0	$1,056	0	$0	$1,056	$1,056
2006	2	0	$0	0	$0	$20,187	0	$0	$20,187	$10,094
2007	2	0	$0	0	$0	$267,564	200	$300,000	$567,564	$283,782
2008	1	0	$0	0	$0	$15,577	30	$45,000	$60,577	$60,577
2009	0	0	$0	0	$0	$0	0	$0	$0	$0
2010	2	8	$75,200,000	51	$50,337,000	$407,516,568	0	$0	$533,053,568	$266,526,784
2011	2	0	$0	0	$0	$302,089	0	$0	$302,089	$151,044
2012	3	0	$0	0	$0	$280,668	500	$750,000	$1,030,668	$343,556
2013	0	0	$0	0	$0	$0	0	$0	$0	$0
2014	4	0	$0	0	$0	$141,019	18	$27,000	$168,019	$42,005
2015	1	0	$0	0	$0	$58	0	$0	$58	$58
Total	23	8	$75,200,000	51	$50,337,000	$411,701,171	776	$1,164,000	$538,402,171	$23,408,790

HCA = high consequence area
VSL = value of statistical life
Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files
1. Inline inspection, pressure testing, direct assessment, and other technology.
2. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
3. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
4. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
5. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-4. Historical Consequences of Gas Transmission Incidents due to Causes Detectable by Modern Integrity Assessment Methods[1] Located in Proposed MCA (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[2]	Number of Injuries	VSL Serious Injury[3]	Other Costs of Accident[4]	Number of Persons Evacuated	Estimated Cost of Evacuation[5]	Total Cost of Incidents	Average Cost per Incident
2003	11	0	$0	0	$0	$12,977,374	13	$19,500	$12,996,874	$1,181,534
2004	7	0	$0	0	$0	$216,205	0	$0	$216,205	$30,886
2005	5	0	$0	0	$0	$102,653,637	240	$360,000	$103,013,637	$20,602,727
2006	14	0	$0	0	$0	$926,494	33	$49,500	$975,994	$69,714
2007	16	1	$9,400,000	3	$2,961,000	$8,312,698	63	$94,500	$20,768,198	$1,298,012
2008	13	0	$0	0	$0	$6,913,847	298	$447,000	$7,360,847	$566,219
2009	9	0	$0	3	$2,961,000	$873,649	207	$310,500	$4,145,149	$460,572
2010	10	0	$0	0	$0	$2,651,682	0	$0	$2,651,682	$265,168
2011	11	0	$0	0	$0	$16,123,614	35	$52,500	$16,176,114	$1,470,556
2012	11	0	$0	0	$0	$3,334,972	22	$33,000	$3,367,972	$306,179
2013	12	0	$0	2	$1,974,000	$8,702,995	451	$676,500	$11,353,495	$946,125
2014	27	0	$0	0	$0	$2,534,887	27	$40,500	$2,575,387	$95,384.70
2015	27	0	$0	0	$0	$2,177,212	27	$40,500	$2,217,712	$82,137
Total	173	1	$9,400,000	8	$7,896,000	$168,399,264	1416	$2,124,000	$187,819,264	$1,085,660

MCA = moderate consequence area (five building in the potential impact radius criterion)
VSL = value of statistical life
Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files
1. Inline inspection, pressure testing, direct assessment, and other technology.
2. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
3. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
4. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
5. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-5. Historical Consequences of Gas Transmission Incidents due to Corrosion (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuation[4]	Total Cost of Incidents	Average Cost per Incident
2003	21	1	$9,400,000	1	$987,000	$10,202,074	171	$256,500	$20,845,574	$992,646
2004	26	0	$0	1	$987,000	$1,171,118	262	$393,000	$2,551,118	$98,120
2005	26	0	$0	1	$987,000	$1,958,592	44	$66,000	$3,011,592	$115,830
2006	32	3	$28,200,000	0	$0	$2,458,396	33	$49,500	$30,707,896	$959,622
2007	34	2	$18,800,000	3	$2,961,000	$5,538,624	138	$207,000	$27,506,624	$809,018
2008	25	0	$0	1	$987,000	$7,808,619	295	$442,500	$9,238,119	$369,525
2009	17	0	$0	0	$0	$1,246,324	83	$124,500	$1,370,824	$80,637
2010	24	2	$18,800,000	7	$6,909,000	$5,372,531	6	$9,000	$31,090,531	$1,295,439
2011	24	0	$0	0	$0	$3,935,920	65	$97,500	$4,033,420	$168,059
2012	20	0	$0	2	$1,974,000	$6,509,273	12	$18,000	$8,501,273	$425,064
2013	25	0	$0	2	$1,974,000	$4,820,896	2567	$3,850,500	$10,645,396	$425,816
2014	22	0	$0	0	$0	$2,216,570	15	$22,500	$2,239,070	$101,776
2015	24	1	$9,400,000	2	$1,974,000	$2,904,165	46	$69,000	$14,347,165	$597,799
Total	320	9	$84,600,000	20	$19,740,000	$56,143,103	3737	$5,605,500	$166,088,603	$519,027

VSL = value of statistical life
Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files
1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-6. Historical Consequences of Gas Transmission Incidents due to External Natural Force Damage Events (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuation[4]	Total Cost of Incidents	Average Cost per Incident
2003	3	0	$0	0	$0	$124,874	0	$0	$124,874	$41,625
2004	5	0	$0	0	$0	$240,779	0	$0	$240,779	$48,156
2005	22	0	$0	0	$0	$1,151,038	0	$0	$1,151,038	$52,320
2006	4	0	$0	0	$0	$108,107	10	$15,000	$123,107	$30,777
2007	6	0	$0	0	$0	$236,541	206	$309,000	$545,541	$90,924
2008	12	0	$0	0	$0	$695,379	0	$0	$695,379	$57,948
2009	9	0	$0	0	$0	$605,516	138	$207,000	$812,516	$90,280
2010	6	0	$0	0	$0	$340,174	0	$0	$340,174	$56,696
2011	16	0	$0	0	$0	$3,566,551	141	$211,500	$3,778,051	$236,128
2012	5	0	$0	0	$0	$1,129,508	30	$45,000	$1,174,508	$234,902
2013	7	0	$0	0	$0	$279,537	0	$0	$279,537	$39,934
2014	13	0	$0	0	$0	$3,026,390	510	$765,000	$3,791,390	$291,645
2015	10	0	$0	0	$0	$404,247	0	$0	$404,247	$40,424.70
Total	118	0	$0	0	$0	$11,908,640	1035	$1,552,500	$13,461,140	$114,077

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-7. Historical Consequences of Gas Transmission Incidents due to Pipe Failure due to Corrosion and Excavation Damage in Class 1 and Class 2 Locations. (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuation[4]	Total Cost of Incidents	Average Cost per Incident
2003	21	1	$9,400,000	1	$987,000	$10,202,074	171	$256,500	$20,845,574	$992,646
2004	26	0	$0	1	$987,000	$1,171,118	262	$393,000	$2,551,118	$98,120
2005	26	0	$0	1	$987,000	$1,958,592	44	$66,000	$3,011,592	$115,830
2006	32	3	$28,200,000	0	$0	$2,458,396	33	$49,500	$30,707,896	$959,622
2007	34	2	$18,800,000	3	$2,961,000	$5,538,624	138	$207,000	$27,506,624	$809,018
2008	25	0	$0	1	$987,000	$7,808,619	295	$442,500	$9,238,119	$369,525
2009	17	0	$0	0	$0	$1,246,324	83	$124,500	$1,370,824	$80,637
2010	24	2	$18,800,000	7	$6,909,000	$5,372,531	6	$9,000	$31,090,531	$1,295,439
2011	24	0	$0	0	$0	$3,935,920	65	$97,500	$4,033,420	$168,059
2012	20	0	$0	2	$1,974,000	$6,509,273	12	$18,000	$8,501,273	$425,064
2013	25	0	$0	2	$1,974,000	$4,820,896	2567	$3,850,500	$10,645,396	$425,816
2014	22	0	$0	0	$0	$2,216,570	15	$22,500	$2,239,070	$101,776
2015	24	1	$9,400,000	2	$1,974,000	$2,904,165	46	$69,000	$14,347,165	$597,799
Total	320	9	$84,600,000	20	$19,740,000	$56,143,103	3737	$5,605,500	$166,088,603	$519,027

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-8. Historical Consequences of Gas Transmission Incidents due to Causes Detectible by Modern Integrity Management Methods[1] Located in Non-HCA Class 3 and Class 4 (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuation[4]	Total Cost of Incidents	Average Cost per Incident
2003	0	0	$0	0	$0	$0	0	$0	$0	$0
2004	2	0	$0	0	$0	$13,506	1	$1,500	$15,006	$7,503
2005	3	0	$0	0	$0	$40,964	100	$150,000	$190,964	$63,655
2006	2	0	$0	0	$0	$93,107	0	$0	$93,107	$46,553
2007	1	0	$0	0	$0	$48	0	$0	$48	$48
2008	3	0	$0	0	$0	$6,409	2	$3,000	$9,409	$3,136
2009	3	0	$0	0	$0	$147,752	99	$148,500	$296,252	$98,751
2010	1	0	$0	0	$0	$8,907	0	$0	$8,907	$8,907
2011	0	0	$0	0	$0	$0	0	$0	$0	$0
2012	2	0	$0	0	$0	$4,188	0	$0	$4,188	$2,094
2013	1	0	$0	0	$0	$1,540,149	175	$262,500	$1,802,649	$1,802,649
2014	2	0	$0	0	$0	$652,110	20	$30,000	$682,110	$341,055
2015	1	0	$0	0	$0	$1,152	0	$0	$1,152	$1,152
Total	21	0	$0	0	$0	$2,508,292	397	$595,500	$3,103,792	$147,800

VSL = value of statistical life
Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files
1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

Table E-9. Historical Consequences of Gas Transmission Incidents due to Causes Detectible by Modern Integrity Management Methods (ILI, Pressure Testing, Direct Assessment, Other Technology) Located Alternate 1 Structure PIR MCA (2003-2013; 2015$)

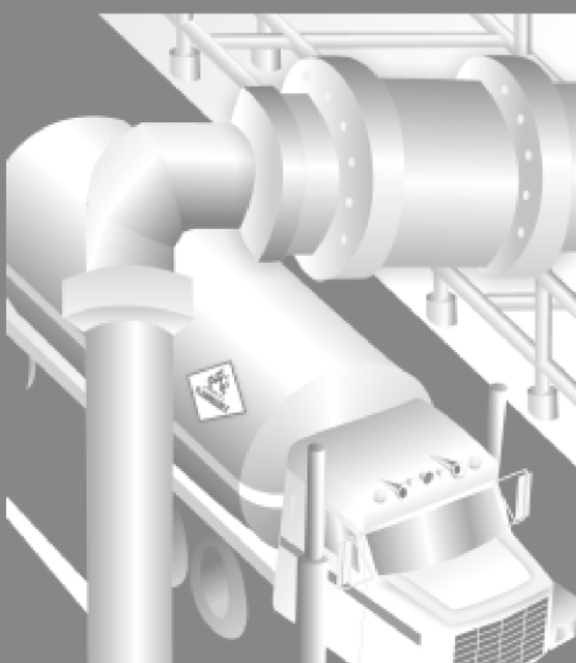
Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuation[4]	Total Cost of Incidents	Average Cost per Incident
2003	26	0	$0	0	$0	$13,155,941	13	$19,500	$13,175,441	$506,748
2004	17	0	$0	0	$0	$219,159	0	$0	$219,159	$12,892
2005	23	0	$0	0	$0	$103,043,595	280	$420,000	$103,463,595	$4,498,417
2006	27	0	$0	0	$0	$1,063,038	42	$63,000	$1,126,038	$41,705
2007	28	1	$9,400,000	3	$2,961,000	$8,478,907	263	$394,500	$21,234,407	$758,372
2008	18	0	$0	0	$0	$6,921,409	300	$450,000	$7,371,409	$409,523
2009	24	0	$0	3	$2,961,000	$923,407	207	$310,500	$4,194,907	$174,788
2010	25	0	$0	0	$0	$3,359,001	0	$0	$3,359,001	$134,360
2011	25	0	$0	0	$0	$16,123,614	35	$52,500	$16,176,114	$647,045
2012	23	0	$0	0	$0	$4,506,211	24	$36,000	$4,542,211	$197,487
2013	26	0	$0	2	$1,974,000	$8,702,995	451	$676,500	$11,353,495	$436,673
2014	10	0	$0	2	$1,974,000	$11,240,623	10	$15,000	$13,229,623	$1,322,962
2015	6	0	$0	2	$1,974,000	$3,732,419	6	$9,000	$5,715,419	$952,570
Total	278	1	$9,400,000	12	$11,844,000	$181,470,320	1631	$2,446,500	$205,160,820	$737,989

VSL = value of statistical life
Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files
1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

NTSB/PAR-03/01
PB2003-916501

Pipeline Accident Report

Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico August 19, 2000



National Transportation Safety Board
Washington, D.C.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the August 19, 2000, natural gas pipeline rupture and subsequent fire near Carlsbad, New Mexico, was a significant reduction in pipe wall thickness due to severe internal corrosion. The severe corrosion had occurred because El Paso Natural Gas Company's corrosion control program failed to prevent, detect, or control internal corrosion within the company's pipeline. Contributing to the accident were ineffective Federal preaccident inspections of El Paso Natural Gas Company that did not identify deficiencies in the company's internal corrosion control program.

Rupture of Hazardous Liquid Pipeline With Release and Ignition of Propane Carmichael, Mississippi November 1, 2007

Accident Report
NTSB/PAR-09/01
PB2009-916501

National Transportation Safety Board

Tests and Research

Metallurgical Examination of Accident Pipe

The rupture extended over a longitudinal distance of about 52 feet 4.75 inches. A major portion of the fracture extended through the longitudinal ERW seam. The downstream end of the fracture crossed a girth weld and continued about 1 inch into the body of the adjoining pipe joint. (See figure 4.) On the upstream side of the ruptured pipe joint, the fracture followed the downstream edge of the circumferential girth weld for about 1.8 inches. At this point it ran longitudinally across the girth weld and then progressed another 1.2 inches along the upstream edge of the girth weld. The fracture then continued along a curved trajectory for about 12 inches into the base metal of the upstream pipe joint, leaving an open flap of pipe at the upstream girth weld. (See figure 5.)

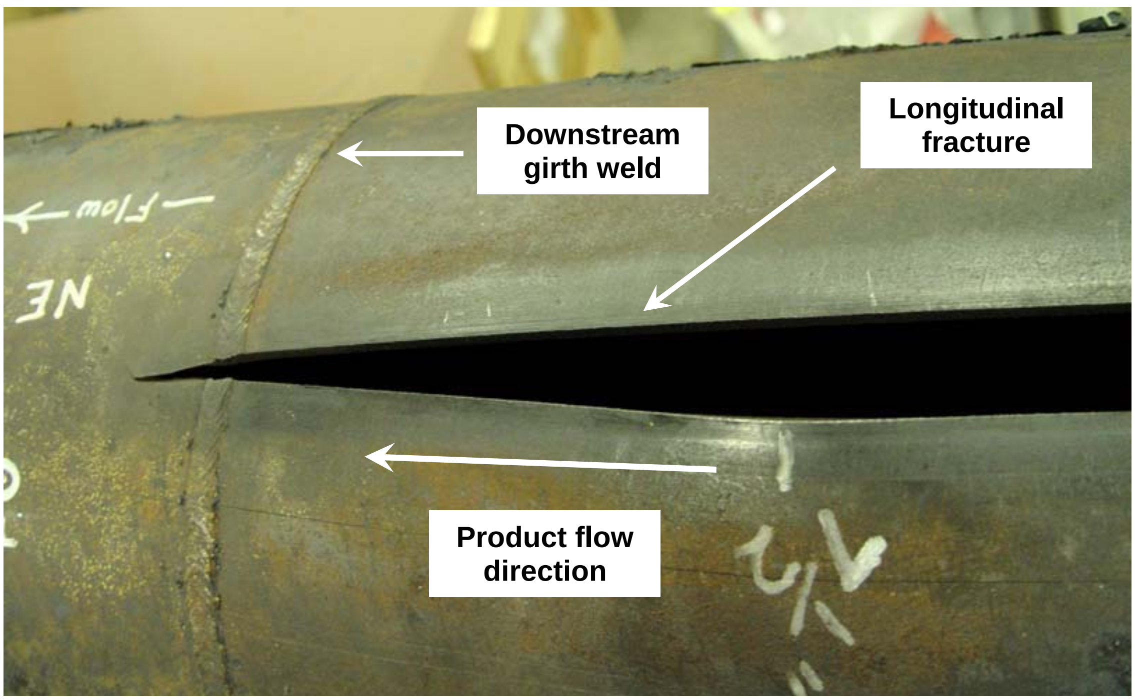


Figure 4. Downstream end of rupture.

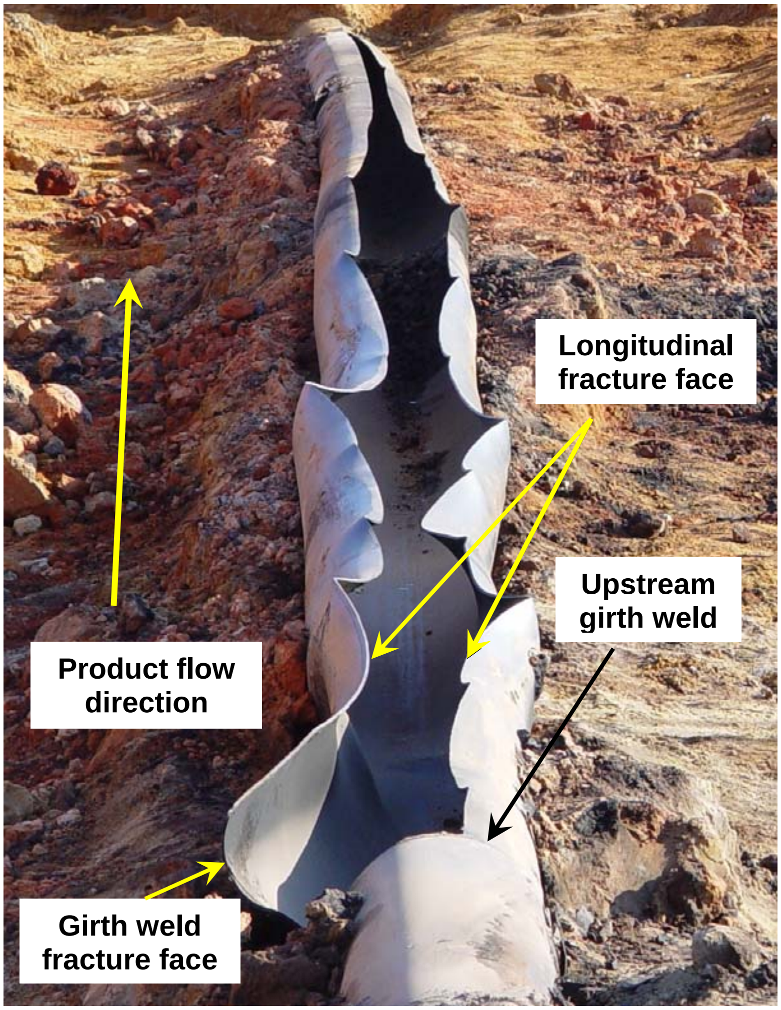


Figure 5. Ruptured pipe.

Fractographic examination[22] of the entire fracture along the longitudinal seam and the upstream girth weld did not reveal a definitive point of fracture origin in the accident pipe, although the fracture faces along both welds had various features of interest that were thoroughly examined during the investigation.

The fracture faces along the seam weld were covered with a layer of oxide that is consistent with exposure to fire. The fracture faces of the seam weld between the center and upstream end of the ruptured pipe joint had regions containing what appeared to be smooth island-like[23] features. In this area the fracture followed the upturned grains that resulted from the ERW process. The island-like features appeared as projections surrounded by a fracture with a rougher texture. In cross-section, the island-like features looked like the letter "J;" they followed

[22] A *fractographic examination* looks at the characteristics of a fracture surface to determine the direction of crack propagation and the fracture mechanisms.

[23] An island feature has a flat top with cliff-like sides above the flat fracture face. On the mating fracture face, the island-like feature extends below the flat fracture face.

Pacific Gas and Electric Company
Natural Gas Transmission Pipeline Rupture and Fire
San Bruno, California
September 9, 2010

Accident Report

NTSB/PAR-11/01
PB2011-916501

National
Transportation
Safety Board

Executive Summary

On September 9, 2010, about 6:11 p.m. Pacific daylight time, a 30-inch-diameter segment of an intrastate natural gas transmission pipeline known as Line 132, owned and operated by the Pacific Gas and Electric Company (PG&E), ruptured in a residential area in San Bruno, California. The rupture occurred at mile point 39.28 of Line 132, at the intersection of Earl Avenue and Glenview Drive. The rupture produced a crater about 72 feet long by 26 feet wide. The section of pipe that ruptured, which was about 28 feet long and weighed about 3,000 pounds, was found 100 feet south of the crater. PG&E estimated that 47.6 million standard cubic feet of natural gas was released. The released natural gas ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area.

Investigation Synopsis

The National Transportation Safety Board's investigation found that the rupture of Line 132 was caused by a fracture that originated in the partially welded longitudinal seam of one of six short pipe sections, which are known in the industry as "pups." The fabrication of five of the pups in 1956 would not have met generally accepted industry quality control and welding standards then in effect, indicating that those standards were either overlooked or ignored. The weld defect in the failed pup would have been visible when it was installed. The investigation also determined that a sewer line installation in 2008 near the rupture did not damage the defective pipe.

The rupture occurred at 6:11 p.m.; almost immediately, the escaping gas from the ruptured pipe ignited and created an inferno. The first 911 call was received within seconds. Officers from the San Bruno Police Department arrived on scene about 6:12 p.m. Firefighters at the San Bruno Fire Department heard and saw the explosion from their station, which was about 300 yards from the rupture site. Firefighters were on scene about 6:13 p.m. More than 900 emergency responders from the city of San Bruno and surrounding jurisdictions executed a coordinated emergency response, which included defensive operations, search and evacuation, and medical operations. Once the flow of natural gas was interrupted, firefighting operations continued for 2 days. Hence, the emergency response by the city of San Bruno was prompt and appropriate.

However, PG&E took 95 minutes to stop the flow of gas and to isolate the rupture site—a response time that was excessively long and contributed to the extent and severity of property damage and increased the life-threatening risks to the residents and emergency responders. The National Transportation Safety Board found that PG&E lacks a detailed and comprehensive procedure for responding to large-scale emergencies such as a transmission pipeline break, including a defined command structure that clearly assigns a single point of leadership and allocates specific duties to supervisory control and data acquisition staff and other involved employees. PG&E's supervisory control and data acquisition system limitations caused delays in pinpointing the location of the break. The use of either automatic shutoff valves or remote control valves would have reduced the amount of time taken to stop the flow of gas.

In 1961, PG&E completed a second relocation project on a portion of Line 132 immediately to the south of the 1956 relocation. As a result, 1,742 feet of the original 1,851 feet of pipe from the 1956 relocation project, including the rupture location, remained in operation. In PG&E's records, this segment is known as Segment 180.

At the time of the accident, Segment 180 was documented in the PG&E GIS as 30-inch-diameter seamless steel pipe API 5L X42 with a wall thickness of 0.375 inch, installed in 1956. The manufacturer is listed as "NA," indicating the information was unknown or unavailable. This portion of the GIS database was populated in 1998 using data from a pipeline survey sheet created in 1977. PG&E discovered during the investigation of this accident that the material specification information for Segment 180 on the 1977 pipeline survey sheet had been obtained from accounting records rather than engineering records. Specifically, the source of the information was a 1956 journal voucher used to allocate material expenses from one construction job to another, which contained an erroneous material description.

After the accident, NTSB investigators discovered that Segment 180 was not X42 seamless pipe, as stated in the GIS database, and that other documents relating to the 1956 project had correctly indicated that the pipe intended for use in that project had a DSAW longitudinal seam. The investigation revealed that seamless pipe was not, and still is not, available in diameters larger than 26 inches. The PG&E director of integrity management and technical support acknowledged in postaccident interviews that during the time when the pipe for Segment 180 was purchased, all 30-inch pipe purchased by PG&E would have been DSAW, not seamless. Investigators also discovered that the material code listed on the journal voucher corresponded to X52 pipe, not X42.

The investigation also revealed that the pipeline at the rupture location was made up of six short pipe segments, known as pups, which were welded together circumferentially. None of the pups were X52 pipe. Each pup ranged from 3.5–4.7 feet long. The NTSB Materials Laboratory determined through tensile and chemical composition testing that the material properties in some of the pups did not meet PG&E 1948 material specifications or industry pipeline material specifications for this time period. The GIS database did not reflect the presence of these pups, although it is intended to record each change in material properties as a separate segment. Further, the investigation revealed that several of the pups had partially welded longitudinal seams that left part of the seam unwelded and that several girth welds joining the pups contained multiple weld defects. Examination revealed that the longer pipe pieces (joints) on either side of the sequence of pups were standard X52 DSAW pipe. (For more information about the pups, see section 1.8, "Examination of Accident Pipe.")

3.2 Probable Cause

The National Transportation Safety Board determines that the probable cause of the accident was the Pacific Gas and Electric Company's (PG&E) (1) inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, which allowed the installation of a substandard and poorly welded pipe section with a visible seam weld flaw that, over time grew to a critical size, causing the pipeline to rupture during a pressure increase stemming from poorly planned electrical work at the Milpitas Terminal; and (2) inadequate pipeline integrity management program, which failed to detect and repair or remove the defective pipe section.

Contributing to the accident were the California Public Utilities Commission's (CPUC) and the U.S. Department of Transportation's exemptions of existing pipelines from the regulatory requirement for pressure testing, which likely would have detected the installation defects. Also contributing to the accident was the CPUC's failure to detect the inadequacies of PG&E's pipeline integrity management program.

Contributing to the severity of the accident were the lack of either automatic shutoff valves or remote control valves on the line and PG&E's flawed emergency response procedures and delay in isolating the rupture to stop the flow of gas.

Battelle

Final Report No. 12-139

Final Report

ERW and Flash Weld Seam Failures

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September 24, 2012

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0533-1101

High-Frequency-Welded ERW (HF-ERW) Pipe

Between about 1960 and 1970, most manufacturers of low-frequency-welded ERW pipe either converted to high-frequency welding (450 kilocycles per second) or went out of business. The high-frequency welding process was easier to control, the equipment was easier to maintain, and it produced weld zones with better resistance to brittle fracture than the low-frequency process. A schematic of a high-frequency welder is shown in Figure 4.

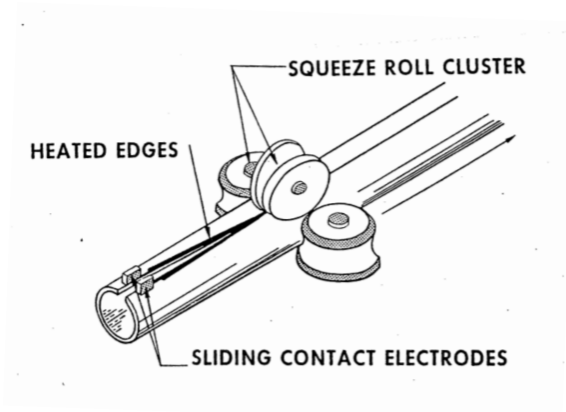

Figure 4. A High-Frequency Welder

A metallographic section across a HF-ERW seam is shown in Figure 5. The narrow, hour-glass-shaped heat affected zone is typical of a high-frequency-welded ERW seam. The contact marks are much smaller than in the case of low-frequency welding. The smaller heat-affected zone and contact marks relative to those of a low-frequency or DC-welded seam are consequences of the fact that the high-frequency current does not penetrate deeply into the material and tends to heat only the material near the bondline sufficiently to change the microstructure. The fact that little or no grain coarsening took place with high-frequency welding meant that the fracture resistance of such seams was generally superior to those formed by low-frequency welding or dc welding. A will be shown, however, the early high frequency welds often exhibited much the same kinds of manufacturing defects that tended to affect LF-ERW and DC-ERW seams.

Table 5. Leak or Rupture Failures

Leak or Rupture	Number of Failures
Leak	71
Rupture	206
Not specified	3

Table 6. Number of Failures by Type of Seam

Type of Seam	Number of Failures
Low-Frequency	153
High-Frequency	48
Direct Current	40
Flash-Welded	37
Not specified	2

Analysis of the Seam Failures by Type of Defect

Cold Welds

The database contains 99 incidents where the cause of failure was attributed primarily to a cold weld (CW). Cold weld refers to a localized area of a weld where no bonding has occurred between the two skelp or plate edges. Cold welds may alternatively be referred to as lack-of-fusion (LOF), however, the term cold weld will be used herein.

The non-bonded region where a complete bondline would be expected consists of a high-melting-temperature oxide that was not sufficiently heated and extruded out of the weld zone. Contamination of the skelp edges, upsets in the welding process (such as current interruptions), or non-optimal welding parameters (too low of heat input, too high a travel speed, or incorrect approach angle) are believed to be factors contributing to the creation of cold welds. Some cold welds extend entirely through the wall thickness while others do not. Those that extend entirely through the wall for only a short length of weld (<< 1 inch) are sometimes referred to as "penetrators". Penetrators are, in fact, a form of cold weld albeit a very short one. It will be seen that they are indistinguishable from cold welds in terms of their characteristics, aside from length. The 8 cases of penetrators that appear in the database are discussed separately at the end of this section on cold welds. It is expected that cold welds (or penetrators) will fail in the manufacturer's hydrostatic test if they are large enough. However, cold welds and penetrators that are small in size will not be eliminated by the mill test.

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Final Interim Report – Task 1.4

Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications

By

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shear, a portion of the upset flow must reverse directions, which is most evident near the mid-thickness – particularly on the left side, as shown in the figure. The resulting weakness is most evident throughout the lower half of this bondline. Given these features, the images in Figure 8 represent a hook crack origin along the bondline, with continued growth into the wall involving flow line separations – much like that for origins located further out into the upset/HAZ. While this failure occurs as a hook origin, it is due to a mill-process issue, with this and other defects due to alignment and other setup aspects grouped into the generic category termed mill defects.

Other Defects and Hook Origins. Much less frequent failures also occur that originate in the upset/HAZ portion of the seam. API 5T1[(23)] identifies several types of defect in this context that are specific to upset autogenous welds. These include: a) contact marks and related arc burns "resulting from the electrical contact between the electrode ….. and the pipe surface," and b) inclusions that are "foreign material or non-metallic material entrapped in the metal during solidification". In addition to these pipe-making issues, other types of defect form where environmentally assisted (EA) processes are active, which typically focus in a locally "hard" microstructure. The locally hard/brittle microstructures develop because a PWHT was not initially part of the autogenous process, or because of an upset in the PWHT, making it ineffective. In general, such failures trace to the presence of hydrogen, due to upsets in the corrosion protection system, or its availability from the transported product. These defects have been variously named, tending to reflect the nature of the indicated cause of the embrittlement or other EA process involved.

In summary, there are several general classes of defect that can form in the autogenous weld process, which include cold welds, penetrators, stitched welds, SSC, hook cracks, and mill defects. Other less frequently occurring defects often involve EA processes.

High Frequency versus Low Frequency ERW and Implications

As discussed above, a major change in the ERW process involved the shift to HFERW and the use of sliding contact, which many consider to be completed for domestic production by the early 1970s. As such, some use the term pre-1970s ERW as a catchall for LFERW; however, because this transition started in the early 1960s for some producers, this descriptor may be inappropriate for some pre-1970s ERW. That said, it also should be noted that there were growing pains with this transition; some HFERW experienced multiple pre-service hydrotest failures, with similar issues plausible in the context of HFI welded pipe. Reporting on metallurgical studies that were reviewed but not tabulated as part of this document showed these often traced to microstructural issues due to source steel, as well as process issues. Thus, the use of pre-1970s ERW might be more relevant to discriminate pipe quality rather than the seam process.

While changes affected via the HFERW/HFI processes can limit the frequency and extent of bondline defects, they do not ensure a quality seam unless clean quality skelp is used, to avoid the same concerns that occurred in the LFERW/FW seams. Accordingly, HFERW/HFI seams can be prone to many of the same issues that occurred for LFERW, particularly where dirty steel opens to hook cracks and SSC. Several papers address defect types that can occur in seams made using HFI/HFERW processes[(e.g.,27,28)], including susceptibility to selective attack in the

seam, which in such cases tends to be termed grooving corrosion[25,29]. Regarding weld-process defects, one paper by an welding equipment producer[27] discusses the "most common defects" and lists nine in total for just the bondline, whereas as noted above process defects also can occur in the upset/HAZ, as well as via grooving corrosion in the bondline depending on the steel used. To be fair, many of the nine seam defects reflect the same concerns as noted for LFERW in regard to cold welds, stitched welds, and penetrators. In fairness it is noted that much has been done in the context detailed research into the HFI/HFERW to understand causes of such defects[e.g.,14,17], and to adapt these processes to limit their formation in production.

Regardless of the improvements affected by the use of high (lower range AM radio / KHz) frequencies and the manner it is introduced into the pipe, there is always a chance for process upsets to cause defects. Thus, avoiding issues in-service is dependent on quality control (QC) and quality assurance (QA), and the use of appropriate pre-service testing in the mill, and then again post-construction. But even with such controls, failures have continued, albeit at reduced rates. In addition to the occurrence of cold welds, hook cracks, and SSC (or grooving corrosion), there are some defect types that are appear unique to the high frequency process[27].

In summary, good steel and a good seam give rise to good pipe – so it takes QC and QA in the steel mill in order to ensure a good seam results from the same QC/QA in pipe-making to produce PSL2 line pipe.

Potential Mechanisms for Defect Growth

Pipelines operate in groundwater and even though coated at some point in their life and nominally subject to CP do experience corrosion (due to holidays in conjunction with upsets in CP), and also are subject to EA processes if the local conditions drive such mechanisms, as for example hydrogen embrittlement. The transported product can also carry constituents that pose a concern from the ID. The following paragraphs illustrate defect growth in regard to both fatigue and stable tearing.

Wherever planar and crack-like defects are present, fatigue due to repeated pressure cycling is a potential mechanism for their growth, as would be hold-times at higher pressure, which motivate growth by stable tearing, sometimes termed stress-activated creep. Certain mill process issues can lead to long axial PTW defects, such as inadequate metal upset and some edge defects can grow by fatigue, as can hook cracks. Figure 9a shows an overview of a secondary crack found nearby an in-service rupture, which was opened in after chilling in liquid nitrogen (LN_2) to reveal the fracture features. Related metallographic cross sections made clear that this was a hook crack, with the initial PTW origin having a depth of roughly half the wall thickness, which runs along almost the full length of this image. Figure 9b shows a slightly magnified view of the fracture surface wherein sequential crack advance is evident, which scanning electron microscopy (SEM) after cleaning indicated was due to fatigue due to pressure cycling of this pipeline that operated under Part 195.

The V-groove formed by SSC, as shown for example in Figure 6, can lead to failure through the net-section by collapse- or fracture-controlled failure, depending on the properties of the seam, the hoop stress relative to the specified minimum yield stress (SMYS), and the length and depth,

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Final Report

Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams

(with an addendum by Brian Leis presenting Battelle's experience with the PAFFC model)

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0533-1101

Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams

(with an addendum by Brian Leis presenting Battelle's experience with the PAFFC model)

J. F. Kiefner and K. M. Kolovich

INTRODUCTION

This document presents an analysis of two known defect assessment methods in an effort to find suitable ways to satisfactorily predict the failure stress levels of defects in or adjacent to ERW or flash-welded line pipe seams. The models to be examined are the Modified LnSec equation and the Raju /Newman equation. Calculations of failure stresses using these two models are compared to actual failure stresses observed for various seam defects in operating pipelines, in pipelines subjected to hydrostatic tests, and in burst tests conducted on pieces of pipes removed from service.

Acknowledgement

The authors greatly appreciate the efforts of Brian Leis in providing special insights concerning the subject of defects in ERW seams. Leis' observations made a valuable contribution to this effort, and the document he prepared on the subject is attached herewith as Appendix A.

BACKGROUND

The need for a model to predict the failure stress levels of ERW seam defects is twofold. First, pipeline operators must respond to the results of seam integrity assessments using ILI crack-detection tools which provide the locations, depths, and lengths of seam anomalies. The rational way for an operator to respond is to prioritize the detected anomalies by their estimated severity, so that the most injurious anomalies are repaired first followed by less injurious anomalies. Second, the operator must be able to predict remaining times to failure for those anomalies that are not repaired, so that a subsequent integrity assessment can be made in a timely manner to prevent the growing anomalies from failing in service. In the case of hydrostatic testing, the test-pressure-to-operating-pressure ratio establishes an initial margin of safety irrespective of the sizes of defects or the material properties, but the operator must calculate remaining lives of anomalies that could have survived the test to know when to test again. In either case, a reliable failure-stress-versus-defect-size model and knowledge of the relevant material properties are necessary for calculating failure stress levels of anomalies. However, as Leis points out in Appendix A of this document, a model that gives conservative answers for the prioritization of

- As Leis has pointed out in Appendix A, a conservative approach is not appropriate for predicting the remaining lives of anomalies that could have survived a particular level of hydrostatic test stress. The appropriate approach for predicting the remaining lives will be presented in the Subtask 2.5 report.
- The K_r portion of a FAD calculation based on an API 579-2/ASME FFS-1 – Fitness-for-Service, Level II calculation could be used in place of the Raju/Newman calculation because the two calculations give virtually the same answers if the same K_c value is used.

Predictions of Failure Stress for Selective Seam Weld Corrosion Defects

Presented in Table 7 are 12 cases involving selective seam weld corrosion defects that failed. The table lists the attributes of the pipeline material, the failure stress as a percent of SMYS, the key pipe body properties, and the dimensions of the anomalies that caused the failures. All of these cases involve either LF-ERW or DC-ERW pipe. Selective seam weld corrosion (SSWC) has been known to occur in flash-welded seams and HF-ERW seams. However, no case of SSWC in a flash-welded seam was contained in the database, and the flaw dimensions for SSWC ruptures in the HF-ERW pipe were unavailable. For cross reference with the Subtask 1.4 report, the Case Number as used in that report is included as well.

Table 7. Attributes of ERW Materials and Selective Seam Weld Corrosion Anomalies that Caused Failures (The yellow highlighted items represent reasonable assumed values where the actual data was not provided.)

SSWC Failure Number	Case Number (from Reference 1)	Diameter, inch	Wall Thickness, inch	Grade	SMYS	Seam Type	Failure Pressure, %SMYS	Pipe Body Properties			Anomaly Dimensions	
								Actual Yield Strength, psi	Actual Ultimate Strength, psi	Charpy Upper Shelf Energy, ft lb (full-	Length, inches	Depth, inch
1	1	10.75	0.279	X46	46,000	ERW - LF	28.5	57,000	74,500	21	5.00	0.165
2	4	12.75	0.250	X52	52,000	ERW - LF	61.6	60,000	76,000	23	6.50	0.165
3	9	8.625	0.250	X42	42,000	ERW - LF	41.1	47,600	63,500	25	1.00	0.175
4	12	18	0.250	X42	42,000	ERW - DC	31.2	52,500	80,500	25	3.30	0.075
5	14	12.75	0.250	X46	46,000	ERW - LF	86.9	56,000	76,500	37	2.00	0.060
6	15	16	0.375	Grade B	35,000	ERW - LF	7.3	51,500	71,000	20	5.40	0.242
7	16	12.75	0.250	Grade B	35,000	ERW - LF	81.2	57,000	77,500	26	3.00	0.220
8	17	8.625	0.203	X42	42,000	ERW - LF	92.3	55,000	74,500	56	1.00	0.183
9	18	8.625	0.203	X42	42,000	ERW - LF	79.7	63,500	81,500	31	3.75	0.100
10	19	10.75	0.219	X46	46,000	ERW - LF	74.7	62,000	73,500	41	3.00	0.110
11	21	12.75	0.312	-	42,000	ERW - LF	31.6	63,000	78,000	18	6.00	0.172
12	22	8.625	0.219	X46	46,000	ERW - LF	47.8	52,000	66,400	16	0.40	0.150

For each selective seam weld corrosion anomaly, two calculations of predicted failure stress levels were made, one using the Modified LnSec equation with the Charpy energy measured for the pipe body material, and one using the Raju/Newman equation with the Charpy energy fixed at 0.4 ft lb. As will become apparent the Raju/Newman equation provides lower bound

Final Interim Report – Task 4.2

Time-Trending and Like-Similar Analysis for ERW-Seam Failures

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First, techniques used during production to detect upsets were not always reliable, and second, the best detection methods do not always identify bondline/seam anomalies that could lead to in-service failures. In this context it is noteworthy that the inability to detect bondline/seam anomalies can be compounded for pipe produced by LF processes when the bondline toughness is reduced as compared to that for the HF processes.

Many conclusions have been drawn over the course of this task, which have been presented throughout this report, and summarized in detail in the last section of the report. The most important of these conclusions follow here:

- Because the LF and HF processes are inherently similar and so can develop many of the same types of anomalies that trace to setup and process upsets or the use of lower-quality skelp, the shift from LF to HF processes can be expected to improve the in-service performance of pipe made via the HF processes only to the extent that specifications and inspections preclude the use of inadequate skelp, and upsets can be avoided, or their deleterious effects reliably detected;
- The HF processes affects more focused heat input that in turn leads to a more refined seam microstructure. This reduces the fracture appearance transition temperature and can lead to increased toughness and critical defect size as compared to the LF processes, all of which facilitate integrity management;
- Time-trending the in-service incidence of failures in HF ERW seams showed that the improvements in the skelp, in process control and detecting upsets affect roughly a factor of ten reduction in the failure rate as compared to that for the LF processes;
- Targeting the industry goal of zero incidents in regard to HF ERW production will require the consistent use of technology to better manage the upsets across the worldwide supply of HF pipe, to reduce the frequency of potentially problematic seam anomalies in entering the US pipeline system; and finally
- Inspection technologies were discussed to detect and size anomalies both during line-pipe production and in-service, all of which target the industry goal of zero incidents through improvements to further reduce the probability of non-detection of potentially problematic seam anomalies.

Kern River Gas Transmission Company,Gas Tariff

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Sheet No. 113, GT&C Measuring Equipment (2.0.0)

GENERAL TERMS AND CONDITIONS
(Continued)

3. MEASURING EQUIPMENT

3.1 Installation and Operation. Transporter will install, maintain and operate at its own expense, at or near each Receipt or Delivery Point, a measuring station properly equipped with meters and other necessary measuring equipment and any related measurement and interconnection facilities; provided, however, that Transporter may require at its option that Shipper bear the expense of furnishing and installing such equipment in any instance in which Shipper requests a new or additional Receipt Point or Delivery Point for Shipper's convenience. Unless otherwise mutually agreed upon, such measuring equipment will be of a type generally accepted in industry practice by which the Volume of Gas received from and delivered to Shipper will be measured. Where orifice meters are used, they will be installed and operated in accordance with ANSI/API 2530, September 1985, and any modifications and amendments thereof, and applied in a practical manner. Where positive displacement meters, turbine meters, ultrasonic meters, or other measuring devices are used, they will be installed and operated in accordance with then-current American Gas Association recommendations, where available, except in circumstances where such meters, located at Delivery Points and modified to enable Transporter to temporarily receive Natural Gas, are used as Receipt Points in the event of an emergency that has caused, or may cause, a significant unscheduled interruption of transportation services on Transporter’s system. Btu measuring equipment will be installed by Transporter at a location or locations where the Total Heating Value of the Gas received and delivered by Transporter can be satisfactorily determined. Btu measurement may also be determined by Gas samples.

3.2 Check Measuring Equipment. Shipper may install, maintain and operate, at its own expense, such check measuring equipment as desired, provided that such equipment will not be installed on property containing Transporter's measuring equipment at or near the Receipt or Delivery Points. However, measurement of Gas for purposes of this tariff will be done by means of the measuring equipment installed pursuant to Paragraph 3.1, except in cases specifically provided to the contrary in this Section 3.

3.3 Notice of Equipment Tests. The party operating the measurement facilities will give notice to the other party of the time and location of all tests of Gas delivered hereunder or of any equipment used in measuring or determining the nature or quality of such Gas, in order that such other party may conveniently have its representative present. Upon request and thirty (30) days written notice, each party will submit to the other its records, together with calculations therefrom, for inspection and verification, subject to return within thirty (30) days after receipt.

Kern River Gas Transmission Company,Gas Tariff

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Sheet No. 114, GT&C Measuring Equipment (1.0.0)

GENERAL TERMS AND CONDITIONS
(Continued)

3. MEASURING EQUIPMENT (Continued)

3.4 Calibration and Test of Meters. The accuracy of Transporter's measuring equipment will be verified by Transporter at reasonable intervals and, if requested, in the presence of representatives of Shipper. In the event Shipper will notify Transporter that it desires a special test of any of Transporter's measuring equipment, the parties will cooperate to secure a prompt verification of the accuracy of such equipment. Any Shipper requesting such a special test of Transporter's measuring equipment will bear Transporter's out-of-pocket costs of the test if the equipment is found to be accurate within one percent (1%).

3.5 Correction of Metering Errors. If, upon test, any measuring equipment, including Transporter's Btu measuring equipment, is found to be in error by not more than one percent, previous recordings of such equipment will be considered accurate in computing deliveries of Gas, but such equipment will be adjusted at once to record accurately.

If, upon test, any measuring equipment is found to be inaccurate by an amount exceeding one percent of the average rate of flow for the period since the last preceding test, such equipment will be adjusted at once to record accurately, and any previous recordings of such equipment will be corrected to zero error for any period which is known definitely; but in case the period is not known or agreed upon, such correction will be for a period extending over one-half of the time elapsed since the date of the last test.

Kern River Gas Transmission Company,Gas Tariff

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Sheet No. 115, GT&C Measuring Equipment (0.0.0)

GENERAL TERMS AND CONDITIONS
(Continued)

3. MEASURING EQUIPMENT (Continued)

3.6 Correction of Stated Metered Volumes. NAESB WGQ 2.3.14: "Measurement data corrections should be processed within 6 months of the production month with a 3 month rebuttal period. This standard will not apply in the case of deliberate omission or misrepresentation or mutual mistake of fact. Parties' other statutory or contractual rights will not otherwise be diminished by this standard."

3.7 Failure of Meters. In the event a meter is out of service or registering inaccurately, the Volume of Gas delivered will be determined:

(a) By correcting the error if the percentage of error is ascertainable by calibration, tests or mathematical calculation; or, in the absence of (a), then

(b) By estimating the Quantity of delivery by deliveries during the periods under similar conditions when the meter was registering accurately; or, in the absence of both (a) and (b), then

(c) By using the registration of any check meter or meters if installed and accurately registering.

3.8 Specific Gravity. The specific gravity of Gas flowing through the meters will be determined by means of a gas chromatograph located at Transporter's measuring station or at any other point on Transporter's system.

3.9 Flowing Temperature. The flowing temperature of the Gas being metered will be determined by means of a recording thermometer of a type acceptable to both parties, installed and maintained in accordance with the specifications set forth in the Gas Measurement Committee Report No. 3, prepared by the Gas Measurement Committee of the American Gas Association, dated September, 1985, or any subsequent revision.

Kern River Gas Transmission Company,Gas Tariff

Filing Category:	Refiled	Filing Date:	08/19/2010
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Sheet Nos. 116-117, (0.0.0)

(RESERVED FOR FUTURE USE)

Kern River Gas Transmission Company,Gas Tariff

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Sheet No. 118, GT&C Quality (0.0.0)

GENERAL TERMS AND CONDITIONS
(Continued)

4. QUALITY

4.1 Gas Quality at Delivery Point(s). The Gas delivered by Transporter for Shipper at the Delivery Point(s):

(a) will be merchantable Natural Gas commercially free from objectionable odors, solid matter, dust, gums, and gum forming constituents, or any other substance which interferes with its intended purpose, or causes interference with the proper and safe operation of the lines, meters, regulators, or other appliances through which it may flow;

(b) will contain not more than seven (7) pounds/MMcf of water;

(c) will contain no hydrocarbons in liquid form at the temperature and pressure at which the Gas is delivered at the Delivery Point;

(d) will not exceed a hydrocarbon dewpoint in excess of fifteen degrees (15) Fahrenheit at pressures up to 800 psig;

(e) will contain not more than 0.2% by volume of oxygen;

(f) will contain not more than 3.0% by volume of carbon dioxide or nitrogen;

(g) will contain not more than a combined total of 4.0% by volume of inerts, including carbon dioxide, nitrogen, oxygen and any other inert compound;

(h) will contain not more than 0.25 grain of hydrogen sulfide per 100 Cubic Feet of Gas (the Gas will not contain any entrained hydrogen sulfide treatment chemical (solvent) or its by-products);

(i) will contain not more than 0.3 grains of mercaptan sulfur per 100 Cubic Feet of Gas;

(j) will contain not more than 0.75 grains of total sulfur per 100 Cubic Feet of Gas;

Kern River Gas Transmission Company,Gas Tariff

Filing Category:	Normal	Filing Date:	02/08/2012
FERC Docket:	RP12-00374-000	FERC Action:	Accept
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Sheet No. 119, GT&C Quality (1.0.0)

GENERAL TERMS AND CONDITIONS
(Continued)

4. QUALITY (Continued)

4.1 Gas Quality at Delivery Point(s). (Continued)

(k) will not contain any toxic or hazardous substance, in concentrations which, in the normal use of the Gas, results in an unacceptable risk to health, is injurious to pipeline facilities, is a limit to merchantability or contrary to applicable governmental standards;

(l) will have a minimum Total Heating Value of not less than nine hundred seventy (970) Btu's per Cubic Foot of Gas on a dry basis;

(m) will have a temperature of not less than forty degrees (40) Fahrenheit, and not more than one hundred twenty degrees (120) Fahrenheit.

4.2 Gas Quality at Receipt Point(s). Gas nominated or delivered by Shipper to Transporter at the Receipt Point(s) for Transportation will comport with the requirements set forth in Paragraph 4.1 herein, or be subject to rejection and non-acceptance by Transporter pursuant to Section 4.5 (with the exception of the following Gas blending rights).

4.3 Gas Blending Rights. Notwithstanding Section 4.2, if the Composite Gas Stream contains less than ninety-five (95)% of the maximum allowable concentration of hydrogen sulfide (4.1(h)), mercaptan sulfur (4.1(i)), total sulfur (4.1(j)), nitrogen or carbon dioxide (4.1(f)), or total inerts (4.1(g)), then Transporter will allow reduced restrictions on said Gas components as described below and Shipper may tender, at any Receipt Point, Gas which contains not more than:

(a) one (1) grain of hydrogen sulfide per 100 Cubic Feet of Gas, subject to the condition that the volume weighted average hydrogen sulfide content of the Composite Gas Stream does not exceed 0.25 grain per 100 Cubic Feet of Gas; and

Kern River Gas Transmission Company,Gas Tariff

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Sheet No. 120, GT&C Quality (1.0.0)

GENERAL TERMS AND CONDITIONS
(Continued)

4. QUALITY (Continued)

4.3 Gas Blending Rights. (Continued)

(b) ten (10) grains of total sulfur per 100 Cubic Feet of Gas, subject to the condition that the volume weighted average total sulfur content of the Composite Gas Stream does not exceed 0.75 grain per 100 Cubic Feet of Gas; and

(c) five (5) grains of mercaptan sulfur per 100 Cubic Feet of Gas, subject to the condition that the volume weighted average mercaptan sulfur content of the Composite Gas Stream does not exceed 0.30 grain per 100 Cubic Feet of Gas; and

(d) four percent (4.0%) by volume of carbon dioxide, subject to the condition that the volume weighted average carbon dioxide content of the Composite Gas Stream does not exceed three percent (3.0%), and the Composite Gas Stream meets the requirements of Section 4.3(f) below; and

(e) six percent (6.0%) by volume of nitrogen, subject to the condition that the volume weighted average nitrogen content of the Composite Gas Stream will not exceed three percent (3.0%), and the Composite Gas Stream meets the requirements of Section 4.3(f) below; and

(f) six percent (6.0%) by volume of inerts, subject to the condition that the volume weighted average total inerts of the Composite Gas Stream will not exceed four percent (4.0%).

4.4 Quality Tests.

(a) Location of Tests. The quality of the Gas received and delivered by Transporter hereunder will be determined by tests which Transporter will cause to be made at Receipt Points, and other locations along its system.

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Sheet No. 121, GT&C Quality (0.0.0)

GENERAL TERMS AND CONDITIONS
(Continued)

4. QUALITY (Continued)

4.4 Quality Tests. (Continued)

(b) Specification for Tests. Transporter will determine the Total Heating Value of Gas and its component analysis at least once each Month in accordance with the Gas Measurement Committee Report No. 3 prepared by the Gas Measurement Committee of the American Gas Association, dated September 1985 or any subsequent revisions (AGA-3). Such determination will be made using either an on-line chromatograph or by chromatographic analysis of a representative sample of Gas taken with a continuous flow proportional sampler. Chromatography will be performed in accordance with Gas Processors Association (GPA) publications 2261-86 and 2286-86 or any subsequent revisions. The values of the physical constants for the Gas components will be determined by the use of the physical constants listed in Table 5 of AGA-3. For components of the Gas not listed in said Table 5, GPA publication 2145-88 or any subsequent revision will be used.

(c) Non-Hydrocarbon Tests. Tests will be made to determine the total sulfur, hydrogen sulfide, mercaptans, carbon dioxide, nitrogen and oxygen content of the Gas, and the hydrocarbon dew point and water vapor content of such Gas by approved standard methods in general use in the gas industry. Tests will be made frequently enough to assure that the Gas continuously conforms to the quality requirements.

4.5 Failure to Conform.

(a) If the Gas offered for Transportation by Shipper will fail at any time to conform to any of the specifications set forth in Section 4.2, then Transporter will have the right, upon written (including by telecopy) or oral notice to Shipper, to immediately refuse to accept all or any portion of such Gas.

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Sheet No. 122, GT&C Quality (0.0.0)

GENERAL TERMS AND CONDITIONS
(Continued)

4. QUALITY (Continued)

4.5 Failure to Conform. (Continued)

(b) Notwithstanding the foregoing, however, in the event the provisions of Section 4.3 are in effect, the following procedures will apply:

(1) When the calculated quality of the Composite Gas Stream approaches 90% of the allowable maximums for those Gas components whose specifications are subject to blending, then Transporter will notify all Shippers whose Gas does not conform with Section 4.2.

(2) When the calculated quality of the Composite Gas Stream equals or exceeds 95% of the allowable maximums for those Gas components whose specifications are subject to blending, Transporter will immediately notify all Shippers whose Gas does not conform that Transporter will commence curtailing receipt of their Gas in the following manner:

(i) Transporter will determine which Gas nominations or receipts do not conform with Section 4.2. For each Shipper whose Gas nominations or deliveries to Transporter do not conform with Section 4.2, Transporter will identify the Quantity of the Gas component that is in excess of the limits set forth in Section 4.2, compute a total thereof for all Shippers, and calculate the percentage of said total for each Shipper.

(ii) The calculated percentage will be used to determine the Quantity of non-conforming component that each of the non-conforming Shippers must eliminate from its Gas nominations and/or deliveries, in order to bring said Composite Gas Stream back to 93% of the quality specifications, of Section 4.2. The required reduction of the non-conforming component will be calculated on the assumption

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Sheet No. 123, GT&C Quality (0.0.0)

GENERAL TERMS AND CONDITIONS
(Continued)

4. QUALITY (Continued)

4.5 Failure to Conform. (Continued)

that Shipper will replace its nominations or deliveries of out of compliance Gas by the required reduction Volume using Gas containing none of the non-conforming component. The required reduction, as well as the newly calculated maximum allowable concentration of the non-conforming component, will be communicated to each of the non-conforming Shippers.

(iii) Shipper will reduce the non-conforming component by either replacing nominated or existing Gas deliveries to Transporter with Gas containing less of the non-conforming component or by reducing nominations or deliveries of non-conforming Gas until, inclusive of the reductions of non-conforming components similarly required of any other non-conforming Shippers, the composition of the Composite Gas Stream is again calculated to contain 93% or less of the maximum allowable quality specifications of Section 4.2.

(iv) Should Shipper fail to take adequate corrective action to comply with its obligation in Section 4.5(b)(2)(iii) to reduce the non-conforming component, Transporter will have the right to curtail receipts of non-conforming Gas from Shipper as determined in Section 4.5(b)(2)(ii) above.

(c) Continuation of Obligation to Pay. In the event Transporter refuses to accept Gas tendered by Shipper because such Gas does not conform to the specifications set forth herein, Shipper will not be relieved of its obligation to pay any Reservation Charge provided for in Shipper's Transportation Service Agreement.

Kern River Gas Transmission Company,Gas Tariff

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Sheet No. 124, GT&C Quality (0.0.0)

GENERAL TERMS AND CONDITIONS
(Continued)

4. QUALITY (Continued)

4.6 Processing Rights. All oil and liquid hydrocarbons separated from the Gas prior to receipt by Transporter will remain the property of Shipper. All liquids or liquefiable hydrocarbons recovered by Transporter, after receipt of Gas hereunder by Transporter and prior to delivery of Gas by Transporter to Shipper, will be and remain the exclusive property of Transporter.

Cover page

The following was docketed at PHMSA-2008-0066-0015 and also considered in connection with the rulemaking “Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments.”

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Houston, TX 77056
Direct: 713.386.3404
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jparks@cpg.com

Columbia Gulf Transmission

James Parks
Director – Integrity

April 25, 2016

Mr. Steve Nanney
General Engineer
United States Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Southwest Region - Office of Pipeline Safety
8701 South Gessner, Suite 1110
Houston, TX 77074

RE: Special Permit PHMSA-2008-0066 Percy Priest Lake Technical Report

Dear Mr. Nanney:

This letter is provided on behalf of Columbia Gulf Transmission, L.L.C. (Columbia Gulf), in response to your email dated April 18, 2016 to Matt Parks of Columbia Pipeline Group concerning the "Draft Report Technical Review of Dent Associated with the Girth Weld at Percy Priest Lake, TN" (Dent Report), dated March 11, 2016 and prepared by Blade Energy. Columbia Gulf has conducted a detailed review of the Dent Report, which was prepared to evaluate the integrity of a dent located in Percy Priest Lake between Hampshire and Hartsville compressor stations on Columbia Gulf Mainline 200. Columbia Gulf has reviewed and accepts the Dent Report findings as outlined in the final report dated April 21, 2016.

Other than waiting until the next assessment interval in (2020), Columbia Gulf is proposing to implement mitigation measures to provide monitoring of changes in dent shape and potential axial loads from ground movement of the pipe at the dent location. As a mitigation measure, Columbia Gulf proposes assessing the interval of Mainline 200 from Hampshire to Hartsville in 2018. The 2018 in-line inspection (ILI) data for the bottom-side dent underwater in Percy Priest Lake, TN will be submitted for a comparison analysis with the previous MFL/caliper ILI data to verify the dent characteristics continue to pose no significant threat to the integrity of this pipeline section. The final comparison analysis report will be submitted to PHMSA.

The 2015 ILI run was conducted utilizing Rosen combined MFL and HR geometry tool. Columbia intends to utilize the same tool technology for the 2018 assessment to keep the data as consistent as possible. In addition, Columbia will perform a minimum of one metal loss and one dent verification dig to ensure the accuracy of the 2018 ILI tool run if there are no anomalies that meet Columbia's investigation criteria.

Columbia is also proposing to implement an additional mitigation measure by conducting a close interval survey of the dent location in Percy Priest Lake in 2018.

If the comparative analysis for the dent confirms that no additional threat to the integrity of this pipeline section exist, Columbia will continue to reassess Mainline 200 from Hampshire to Hartsville in 2020 following the normal schedule as set out in the Special Permit PHMSA-2008-0066.

If you have any questions or would like additional information, please do not hesitate to contact me.

Sincerely,

James Parks
Director – Integrity
Columbia Gulf Transmission, LLC

3 Objective & Workscope

The objective of this work is to determine the immediate and future conditions of the Percy Priest Lake dent affecting girth weld.

The work scope is as follows:

- ☐ First, review available failure reports in this section, evaluate the potential threats, generate material data and ascertain the quality of girth weld.
- ☐ Review consecutive MFL inspection data for coincident damage in the dent or associated girth weld region. Perform global pipeline curvature-based strain analysis using recent IMU inspection data to ascertain any change in the pipeline profile/location, especially at the lake region.
- ☐ Review the recent Close Interval Survey (CIS) data performed in this pipeline section to infer the condition of cathodic protection of this dented pipe joint.
- ☐ Compare dent profile between the recent and past geometry inspections (2005 – 2015) to estimate whether significant changes in dent depth and shape occurred in last decade.
- ☐ Identify and then, quantify all loads acting on the dent that will then serve as a basis for engineering critical assessment
- ☐ Evaluate the strain level associated with this dent affecting girth weld using FEA, and calculate the plastic strain limit damage factors to infer the possibility of a crack.
- ☐ Estimate the fatigue life of this dent using FEA with the operational pressure data and different fatigue life prediction models.

Sections 4 through 9 describe in detail the approach and the results.

of cycles to failure based on S-N life methodology for this 4.6%OD dent affecting girth weld.

Table 10: Number of cycles to failure based on API 1156 methodology

Approach	Equation	Stress Intensity Range from FEA, ($\Delta\sigma$, psi)	Number of cycles to failure, (N_f , cycles)	Equivalent number of cycles from Rainflow, (N_{eqv} , cycles/year)	Predicted Fatigue Life, (year)	Comment
Percy Priest Lake Dent - Stress range obtained from FEA	API 1156 Equation (by Alexandar et al)	175598	24977	0.22	113530	No safety factor considered on the cycle number
	ASME BPVC Divison 2 (S-N curve)	175598	1249	0.22	5679	Safety factors considered on both stress and cycles

With the FEA results, the predicted fatigue life of this dent is between 5679 and 113530 years utilizing the conservative ASME BPVC Division 2 design S-N life curve and the API 1156 equation, respectively. In summary, the API 1156 fatigue life equation predicted more than 100 years of life for the lake dent.

10.2.2 PRCI-BMT Fatigue Life Equation

Under the PRCI research sponsorship[24], BMT Fleet Technology Ltd (BMT) recently developed a dent fatigue assessment methodology based on the data generated through work of full scale fatigue testing of dents (PRCI MD 4-2, DoT 339 and PRCI MD 4-9.[28-29].

Based on the dent fatigue test data and elastic-plastic finite element analysis result, the BS 7608 Class D mean -1 standard deviation(-1 sd) curve was chosen by BMT as an appropriate S-N curve that provides a conservative estimate of the fatigue life. The equation for the BS 7608 Class D mean-1sd S-N curve is given below:

$$\log_{10}(N) = 12.3912 - 3\ \log_{10}(S_r) \qquad (2)$$

Whereas,

N = number of cycles to failure

S_r = stress range in MPa

Using the stress intensity range obtained from FEA for this dent and with conservative PRCI-BMT equation, the predicted minimum fatigue life for this dent is 6305 years. This estimation is consistent with fatigue estimation obtained from ASME BPVC Division 2 S-N life curve, which is also a conservative design curve. Table 11 shows the calculated fatigue life using PRCI-BMT fatigue equation.

Table 11: Number of cycles to failure based on PRCI-BMT BS-7608 Class D Equation

Methodology	Stress Intensity Range from FEA, ($\Delta\sigma$, MPa)	Number of cycles to failure, (N_f , cycles)	Equivalent number of cycles from Rainflow, (N_{eqv} , cycles/year)	Predicted fatigue Life, (year)	Comment
PRCI-BMT (BS 7608 Class D Mean-1sd S-N life curve	1211	1387	0.22	6305	Minus 1 standard deviation included

July 7, 2016

<u>Via www.regulations.gov and email</u>

Marie Therese Dominguez
Administrator
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
1200 New Jersey Avenue, S.E.
Washington, DC 20590-0001

Re: Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines (Docket ID: PHMSA-2011-0023)

Dear Administrator Dominguez:

The Interstate Natural Gas Association of America (INGAA), a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry in North America, respectfully submits these comments in response to the "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines" Notice of Proposed Rulemaking (NPRM). INGAA will file certain attachments under separate cover.

INGAA appreciates your consideration of these comments.

Sincerely,

Donald F. Santa
President and CEO
Interstate Natural Gas Association of America
20 F Street, N.W., Suite 450
Washington, DC 20001
(202) 216-5900

UNITED STATES OF AMERICA
BEFORE THE
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Safety of Gas Transmission	**§**	
and Gathering Pipelines	**§**	**Docket No. PHMSA-2011-0023**
	§	

COMMENTS OF
THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

UNITED STATES OF AMERICA
BEFORE THE
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Safety of Gas Transmission	§	
and Gathering Pipelines	§	**Docket No. PHMSA-2011-0023**
	§	

Comments of
The Interstate Natural Gas Association of America

I. Introduction

The Interstate Natural Gas Association of America (INGAA) offers these comments on the Notice of Proposed Rulemaking (NPRM) issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) on April 8, 2016.[1]

INGAA is a trade association representing approximately two-thirds of the nation's natural gas transmission pipeline systems. INGAA's 24 members operate approximately 200,000 miles of interstate gas transmission pipelines.

Pipeline safety is the top priority of INGAA and its members. INGAA strongly supports regulations that embrace and advance improvements in pipeline safety practices, with the intent of achieving the goal of zero incidents. For the last 15 years, INGAA members have achieved significant advances in safety through implementation of PHMSA's integrity management regulations in Subpart O of Part 192. INGAA supports the process of risk and threat identification, prioritization, data integration, prevention and mitigation, with the foundation of continuous improvement.

Based on its commitment to safety, INGAA advanced its Integrity Management Continuous Improvement (IMCI) initiative in 2011. The scope of this voluntary initiative is broad, extending the protections of integrity management practices beyond High Consequence Areas (HCAs) to all people living, working and recreating near an interstate natural gas transmission pipeline. INGAA has engaged with many stakeholders, including PHMSA, state regulators, the National Transportation Safety Board (NTSB), and various public advocacy groups (including the Pipeline Safety Trust) to develop specific programs to advance IMCI commitments. The lessons learned from operators' experiences are significant. In considering additional regulatory initiatives, PHMSA should consider and apply the lessons learned from INGAA's experience.

[1] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 20,722 (Apr. 8, 2016) (NPRM).

INGAA has identified key provisions in the NPRM that PHMSA should modify to improve pipeline safety. In several instances, the NPRM requirements will have unintended consequences that actually hinder the continued advancement of pipeline safety practices. They also will increase safety risks and adverse environmental impacts, discourage the implementation of advanced technologies, and adversely affect the reliability of the national natural gas pipeline grid. INGAA offers alternative approaches and regulatory language that would more effectively promote safe pipeline practices and meet the goals of the NPRM without compromising the reliable delivery of natural gas.

Given the complexity of the NPRM, INGAA urges PHMSA to convene a public workshop to permit stakeholders and interested entities to identify and discuss their concerns and possible alternatives to the NPRM. If PHMSA does not convene a workshop, then INGAA is willing to work with the PHMSA and other trade associations, state regulators, public representatives to provide an open public forum to discuss comments filed by stakeholders to the NPRM.

effectively. The criteria proposed in the NPRM do not reflect such advances, as evidenced by references to a version of ASME B31.8S – 2004 that is outdated.

5. PHMSA's Proposed Immediate "Repair" Criteria Should Be Renamed "Response" Criteria.

a. Remaining Strength – §§ 192.713(d)(1)(i) and 192.933(d)(1)(i)

PHMSA proposes to require operators to repair anomalies with a predicted failure pressure less than or equal to 1.1 times the MAOP using B31G, RSTRENG or equivalent as an immediate response condition. As discussed above, INGAA proposes that anomalies with a predicted failure pressure less than or equal to 1.1 times the MAOP using B31G, RSTRENG or equivalent be investigated as an immediate condition. Repairs would be made using § 192.713(c) and INGAA's proposed § 192.933(e).

INGAA proposes to change how PHMSA proposes to address cracks and crack-like features. INGAA proposes that PHMSA treat crack-like features the same as it treats metal loss, applying remaining strength calculations. While addressed separately in proposed § 192.713(d)(1)(v) and proposed § 192.933(d)(1)(vi), B31.8S recognizes treating the remaining strength of cracks and metal loss similarly.[176] PHMSA should permit operators to respond to cracks, using the well-established Modified Ln Sec analysis method or an equivalent method. INGAA proposes that PHMSA permit operators to use this methodology for responding to cracks rather than responding immediately upon "[a]ny indication of significant stress corrosion cracking (SCC)," as proposed by § 192.713(d)(1)(v) and proposed § 192.933(d)(1)(vi). INGAA's proposal represents a practical and analytical engineering-based approach that is consistent with, and equally as safe as, PHMSA's proposed approach for responding to metal loss. INGAA requests that PHMSA modify proposed § 192.713(d)(1)(i) and proposed § 192.933(d)(1)(i), to allow operators to analyze cracks through methodology such as Modified Ln-sec and to respond according to the evaluated predicted failure pressures. Using this criteria, a crack with a predicted failure pressure less than or equal to 1.1 times MAOP would be an immediate response condition.

PHMSA has recognized in the NPRM that a pipeline that has been pressure tested in accordance with Subpart J test levels can contain manufacturing-related features, which will remain resident unless otherwise acted upon by pressure cycling or outside forces. INGAA proposes new language that stipulates that manufacturing-related features only require a response if the segment has not been tested in accordance with Subpart J test levels.

[176] ASME B31.8S-2012, Managing System Integrity of Gas Pipelines, Code for Pressure Piping at 51, Table A-3.4-1.

b. Dents That Have Any Indication of Metal Loss, Cracking or Stress Riser - §§ 192.713(d)(1)(ii) and 192.933(d)(1)(ii)

PHMSA proposes to require that operators repair dents that have any indication of metal loss, cracking or stress riser. PHMSA has not provided any empirical basis for its proposal. In contrast, ASME B31.8 states that dents associated with metal loss due to corrosion are not injurious except when the metal loss exceeds remaining strength limitations or the dent containing metal loss is greater than 6% of nominal pipe diameter.[177]

The proposed PHMSA rule also does not consider the orientation of a dent with metal loss (*e.g.*, top or bottom of the pipe) to establish the likelihood that the metal loss is the result of mechanical damage rather than non-injurious corrosion. Dents with metal loss on the bottom of the pipe should not require an immediate repair since they are not injurious and typically are corrosion-related. The experience of INGAA members indicates that the vast majority of dents with metal loss identified through in-line inspection tools are associated with corrosion-related metal loss levels that are not injurious when examined and do not require repair in accordance with B31.8-2007 criteria.

Requiring an immediate repair for anomalies that do not represent an injurious condition conflicts with PHMSA's intent in establishing immediate response conditions. If adopted, this criterion would divert resources and distract pipeline operators from addressing conditions that do, as demonstrated by risk data, warrant immediate response. Addressing non-injurious dents with metal loss as immediate conditions also conflicts with various industry standards and guidance. For example, ASME B31.8S-2004, Section 7.2 classifies responses into three groups: immediate; scheduled; and monitored. According to Section 7.2, the indication within the immediate grouping is one that "shows that the defect is at failure point." ASME B31.8S-2004, Section 7.2.3 states that "[i]ndications requiring immediate response are those that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline."

INGAA proposes to address "[a] dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser" as an "immediate response" condition, because it is likely caused by excavation damage. Gouging caused by mechanical damage is much more difficult to size and evaluate reliably. In light of these difficulties, the consensus standards require a more conservative approach. Addressing these top-side dents as immediate response conditions is consistent with the approach reflected in § 195.452(h)(4)(i)(C), applicable to hazardous liquid pipelines.[178] In contrast, bottom-side dents

[177] ASME B31.8-2007, Gas Transmission and Distribution Piping Systems, Code for Pressure Piping at 69, Section 851.41.

[178] 49 C.F.R. § 195.452(h)(4)(i)(C).

that have any indication of metal loss under Part 195 have a 60-day response condition.[179] PHMSA recognizes that dents on the bottom of the pipe are highly likely to be corrosion-related metal loss, which an operator can detect the size and evaluate reliably (and not be an immediate repair condition).[180] INGAA proposes that PHMSA treat bottom-side dents in the same manner.

c. Metal Loss or Crack-Like Feature Greater Than 80% - §§ 192.713(d)(1)(iii) and 192.933(d)(1)(iv)

INGAA agrees with PHMSA's proposal to include a metal loss depth criterion as long as it is considered a response criterion. INGAA further recommends the addition of an 80% depth-based cracking criterion as an immediate condition along with the metal loss depth-based criteria. While PHMSA may not have proposed a cracking criterion as an immediate condition, INGAA recommends adding it to these above-referenced regulations making them consistent with the way PHMSA addresses metal loss.

d. Metal-Loss Affecting a Detected Longitudinal Seam - §§ 192.713(d)(1)(iv) and 192.933(d)(1)(v)

PHMSA proposes that "[a]n indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high frequency electric resistance welding (ERW) or by electric flash welding" is an immediate repair condition. Metal-loss affecting a direct current or low-frequency electric resistance weld or electric flash weld is recognized already in ASME B31.8S-2004 as a condition requiring an immediate response.[181]

PHMSA has not explained or provided data to support its proposal to treat metal loss associated with high-frequency electric resistance welded seams as an immediate repair condition. PHMSA's position also is inconsistent with B31.8S-2004, Section 7.2.1, which does not treat high-frequency electric resistance welded seams as an immediate repair condition.

Corrosion-related metal loss interacting with high-frequency electric resistance weld seams is not subject to selective seam weld corrosion and not considered an injurious condition under any known industry standard. Responding to non-injurious conditions would not improve pipeline safety because it would deploy pipeline integrity resources at the expense of higher-risk conditions elsewhere. This condition does not necessarily meet the standards established in ASME B31.8S-2004, Section 7.2, which provides that "Indications requiring immediate response are those that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline." Corrosion interacting with high-

[179] 49 C.F.R. § 195.452(h)(4)(ii)(B).
[180] 49 C.F.R. § 195.452(h)(4)(iii).
[181] ASME B31.8S-2004, Managing System Integrity of Gas Pipelines at 20, Section 7.2.1.

frequency ERW is non-injurious and does not meet either an immediate or scheduled response requirement.

Responding to defects that do not meet the criteria for an immediate condition undermines an operator's ability to respond in a timely manner to defects that are in fact immediate response conditions. Classifying indications that are not "expected to cause immediate or near-term leaks or ruptures" as immediate response conditions would potentially slow the response to conditions that represent a higher risk to the public and the environment. INGAA requests that PHMSA remove metal-loss affecting a detected longitudinal seam, if that seam was formed *by high-frequency electric resistance welding* from the immediate repair conditions of §§ 192.713(d)(1)(iv) and 192.933(d)(1)(v) .

e. Any Indication of Significant Stress Corrosion Cracking (SCC) – §§ 192.713(d)(1)(v) and 192.933(v)(1)(vi)

PHMSA proposes that "any indication of significant stress corrosion cracking (SCC)" be an immediate condition. PHMSA proposes to define "significant stress corrosion cracking" as it is defined in NACE SP0204-2008 – Stress Corrosion Cracking Direct Assessment.[182] This definition is not part of the current NACE standard and was never intended by NACE to be used for response to ILI or to drive repair decisions. PHMSA also notes that "Stress Corrosion Cracking is listed in ASME/ANSI B31.8S as an immediate repair condition, which is not reflected in the current IM regulations." PHMSA, however, relies upon an outdated 2004 version of B31.8S, which considered response based on the then-recognized capabilities of ILI and does not reflect current ILI capabilities. ASME B31.8S-2010 and later versions treat significant cracking similar to metal loss.

PHMSA further justifies the proposed criteria by citing NTSB recommendation P-12-3. NTSB recommended an "engineering assessment of crack defects," establishing "acceptable methods for performing these engineering assessments" and consideration of "safety factors," which are not addressed within the PHMSA proposal. PHMSA's approach lacks a rational connection to the risks posed by SCC and does not reflect the current technology of ILI tools or modern industry consensus standards, which provide models for evaluating cracks effectively.

PHMSA should delete §§ 192.713(d)(1)(v) and 192.933(d)(1)(vi), "significant stress corrosion cracking," as an immediate repair condition. It should instead reference the failure pressure ratio approach to managing SCC in §§ 192.713(d)(1)(v) and 192.933(d)(1)(vi), which is a more practical engineering-based approach. INGAA's proposed criteria would allow an

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[182] *Compare* NACE SP0203-2008, Stress Corrosion Cracking (SCC) Direct Assessment at 6 (definition of "Significant SCC") and proposed § 192.3 (definition of "Significant stress corrosion cracking"). Note that the NACE definition states that "a crack that is labeled "significant" is not necessarily an immediate threat to the integrity of the pipeline."

operator to calculate a failure pressure and then apply a sufficient safety factor, consistent with PHMSA's approach for metal loss corrosion, in §§ 192.713(d)(1)(v) and 192.933(d)(1)(vi) above. "Significant stress corrosion cracking" is an obsolete term that is not used in the current NACE standard or the current version of the CEPA recommended practice [183] from which the term originated.

"Significant Stress Corrosion Cracking" was first defined in the CEPA Stress Corrosion Cracking Recommended Practice developed in 1997. The term originated in the context of an early form of stress corrosion cracking direct assessment. This term was adopted in the NACE stress corrosion cracking standard, but only in context of establishing a mitigation program such as performing ILI or pressure testing. The definition of "Significant SCC" in the NACE SP0204-2008 standard includes the qualification that "a crack that is labeled significant is not necessarily an immediate threat to the integrity of the pipeline." This demonstrates that the term was never intended to drive response or repair decisions. The term has been removed from the latest versions of both the NACE SCCDA standard CP0204-2015 and the CEPA SCC recommended practice.

INGAA also proposes to incorporate principles from the current industry standards, B31.8S-2014, rather than continue to rely on the outdated 2004 version. The current standards enable operators to evaluate cracking, rather than repair it immediately. The outdated ASME B31.8S-2004, Section 7.2.2 addressed response for "Crack Detection Tools for Stress Corrosion Cracking" and stated that "[a]ll indications of stress corrosion cracks require immediate response." This requirement was written in the context of the far more limited ILI crack detection technologies available at that time. Since then, three updated versions of ASME B31.8S have been published. Each version of B31.8S has updated the language for response to SCC to reflect advances in both Electromagnetic Acoustic Transducer (EMAT) technology and fracture mechanics evaluation capabilities. There is no longer a need to classify all indications of SCC as an immediate response condition, because technology is much better at detecting and sizing SCC for more refined analyses.

PHMSA recognizes EMAT technology in proposed § 192.624(c)(3)(iii) and PHMSA similarly should recognize EMAT technology in proposed § 192.713(d)(1)(i) and § 192.933(d)(1)(i) to address cracks. In §192.624(c)(3)(iii), PHMSA states that "[a]t a minimum, the operator must conduct an assessment using high resolution magnetic flux leakage (MFL) tool, a high resolution deformation tool, and either an electromagnetic acoustic transducer (EMAT) or ultrasonic testing (UT) tool." The last three versions of ASME B31.8S Section 7.2.2 (2010, 2012, and 2014) state that "[i]t is the responsibility of the operator to develop and document appropriate assessment, response, and repair plans when in-line inspection (ILI) is

[183] Canadian Energy Pipeline Association, Stress Corrosion Cracking Recommended Practices at 1-1 (2nd ed. Dec. 2007).

used for the detection and sizing of indications of stress corrosion cracking (SCC)" and no longer mandates immediate response for all cracks. Although ASME B31.8S-2014 assigns responsibility to the operator, INGAA supports a defined crack response approach that requires an operator to establish the burst or failure pressure and then establish response criteria based on safety factor thresholds, similar to the approach PHMSA proposes for conventional corrosion metal loss in proposed § 192.713(d)(1)(i) and § 192.933(d)(1)(i). INGAA proposes that PHMSA allow an operator to evaluate cracks in accordance with the current version ASME B31.8S-2014. PHMSA should require an operator to schedule an immediate response when a predicted failure pressure is less than or equal to 1.1 times the MAOP.

PHMSA also references the Marshall, Michigan, crude oil spill incident and subsequent NTSB recommendations to justify its proposal to respond to all cracks as immediate conditions. PHMSA states:

> With respect to SCC, PHMSA has incorporated repair criteria to address NTSB recommendation P-12-3 that resulted from the investigation of the Marshall, Michigan crude oil accident. From its investigation, the NTSB recommended that PHMSA revise § 195.452 to clearly state (1) when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed; (2) the acceptable methods for performing these engineering assessments, including the assessment of cracks coinciding with corrosion with a safety factor that considers the uncertainties associated with sizing of crack defects; (3) criteria for determining when a probable crack defect in a pipeline segment must be excavated and time limits for completing those excavations; (4) pressure restriction limits for crack defects that are not excavated by the required date; and (5) acceptable methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or stress corrosion cracking as applicable (NTSB recommendation P-12-3). Although the recommendation was focused on Part 195, the issue applies to gas pipelines regulated under Part 192.

NPRM at 20,819.

None of the NTSB recommendations support a requirement to examine and evaluate SCC on the basis of a misapplied and obsolete term that originated from direct assessment processes. To the contrary, the first part of NTSB recommendation P-12-3 recommends that PHMSA clearly state "when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed," and the second part recommends that PHMSA establish "the acceptable methods for performing these engineering assessments," including consideration of safety factors. PHMSA's proposed criteria for immediate response do not address either of these recommendations. INGAA's proposed approach and language fulfills the NTSB recommendations by providing an engineering-based solution (*i.e.*, calculation of burst pressure

with applied safety factors) and proposed acceptable methods (*e.g.,* Modified Ln Sec or equivalent).

Responding to defects that do not meet the purpose of the immediate response conditions requirement also undermines the response timing for those defects that do meet the definition of immediate response conditions. Classifying indications that are not "expected to cause immediate or near-term leaks or ruptures" as immediate response conditions would potentially slow the response to indications that are legitimate immediate conditions and represent a higher risk to the public and the environment. INGAA requests PHMSA delete § 713(d)(1)(v) and § 192.933(d)(1)(vi). INGAA also requests PHMSA allow operators to manage SCC similar to metal loss as a function of MAOP.

f. Any Indication of Significant Selective Seam Weld Corrosion (SSWC) – PHMSA Should Delete § 192.713(d)(1)(vi) and § 192.933(d)(1)(vii)

PHMSA proposes that operators treat any significant indication of selective seam weld corrosion as an immediate response condition. Because in-line inspection tools cannot reliably identify selective seam weld corrosion and it can be conclusively identified only with visual examination and evaluation. INGAA proposes to move this language to §192.713(d)(1)(iv) and § 192.933(d)(1)(v). In addition, §192.713(d)(1)(vi) and § 192.933(d)(1)(vii) are unnecessary and should be deleted, because response to ILI tool data related to the potential threat of selective seam weld corrosion is addressed using the failure pressure ratio methods described in proposed §192.713(d)(1)(i) and § 192.933(d)(1)(i).

F. Pressure Reductions For Immediate Response Conditions - § 192.713(d)(2): PHMSA's Proposal to Reduce Pressure to the Lower of Two Pressure Reduction Methodologies Is Inconsistent With Existing Regulations and Would Not Add Incremental Safety Benefits.

PHMSA proposes to require an operator to reduce the operating pressure of its affected pipeline until it can remediate the immediate repair conditions identified in § 192.713(d)(1). PHMSA proposes under § 192.713(d)(2)(i) that if SMYS or actual material yield and ultimate tensile strength is not known or adequately documented by RTVC records, the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607, or reduce pressure to 80 % at time of discovery, *whichever method is lower*. PHMSA has not offered any risk-related rationale or other support for the proposed methods for determining an appropriate pressure reduction. It also does not account for industry's ability to conduct engineering analyses to evaluate and calculate safe pressures. INGAA proposes that § 192.713 be changed to give operators the discretion to choose between using engineering analysis, such as B31G or R-STRENG, *or* taking a pressure reduction to 80% of the operating pressure at the time of discovery (without the requirement to use the "lower of" the two options).

X. Internal Corrosion §§ 192.478 and 192.935

In §§ 192.478 and 192.935, PHMSA proposes new requirements for managing internal corrosion applicable to all transmission pipelines. PHMSA has failed to justify its proposal in § 192.478 to require that all operators develop and implement prescriptive monitoring and mitigation plans to identify potentially corrosive constituents being transported and mitigate their potential corrosive effects. NPRM at 20,830. As required by existing 49 C.F.R. § 192.477, operators already have plans to address potentially corrosive constituents based on the operational attributes of affected pipe segments. The proposed regulations are too prescriptive, unnecessary and overly broad. If implemented, these requirements will increase costs without increasing safety. PHMSA also has not justified its proposal in § 192.935 to require the operators of all pipe segments located in HCAs comply with new, comprehensive and prescriptive internal corrosion measures. INGAA is particularly concerned with the proposed new preventive and mitigative requirement in § 192.935(f) that operators install "continuous gas quality monitoring equipment" at all points where gas with potentially deleterious contaminants enter the pipeline. NPRM at 20,846.

A. PHMSA's Proposed Changes to Certain Internal Corrosion Control Requirements in Proposed § 192.478 Are Duplicative and Unnecessary.

PHMSA proposes to adopt a new internal corrosion requirement in proposed § 192.478 that would require operators to implement programs for monitoring, evaluating, and mitigating the effects of potentially corrosive constituents on the internal condition of a pipe. Under proposed § 192.478, potentially corrosive constituents would include carbon dioxide, hydrogen sulfide, sulfur, microbes, and free water (whether acting individually or in combination). Onshore gas transmission operators would be required to evaluate each corrosive constituent (either individually or in combination with other corrosive constituents) and assess the effect of those constituents on the internal condition of the pipe and implement mitigation measures. The proposed monitoring and mitigation program would require the use of continuous gas quality monitoring equipment at points where potentially corrosive contaminants enter a pipeline, and the use of product sampling, inhibitor injections, cleaning pigs, filters/separators, or other technology to mitigate the effects of these contaminants. NPRM at 20,830.

Section § 192.478(b)(3) would require onshore gas transmission operators to conduct an evaluation *twice* each calendar year, at intervals not to exceed 7.5 months, to determine if internal corrosion is being effectively monitored and mitigated. This type of monitoring is required only once per year in HCA pipe operating at pressures below 30 % of SMYS.[186] The

[186] *See* 49 C.F.R. § 192.941.

proposed regulation states that coupons or other suitable means must be used to determine the effectiveness of an operator's internal corrosion mitigation measures, and that each coupon or other means must be evaluated twice each calendar year, not to exceed 7.5 months. Onshore gas transmission operators also would be required to review the proposed internal corrosion monitoring and mitigation program at least twice each calendar year, not to exceed 7.5 months, to determine if adjustments are necessary.

Proposed § 192.710(c)(8)(ii) also contains internal corrosion monitoring provisions that are applicable to pipe segments with an MAOP less than 30 % of SMYS. Operators of such lines would be required to conduct a gas analysis for corrosive agents at least two times per year. For segments located in a storage field, an operator would be required to test fluids removed from the storage field on an annual basis, § 192.710(c)(8)(ii)(B), rather than twice each calendar year as required under § 192.478(b). The NPRM does not explain the relationship between § 192.710(c)(8)(ii)(B) and § 192.478(b).

To justify the proposed changes, PHMSA asserts that "the current requirements for internal corrosion control are non-specific," and that "there is benefit in enhancing the current internal corrosion control requirements to establish a more effective minimum standard for internal corrosion management." NPRM at 20,784. PHMSA also acknowledges that, while existing § 192.477 requires that an operator monitor lines carrying corrosive gas for internal corrosion, "the existing rules do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system changes, changing gas supply, upset conditions, or other changes." NPRM at 20,810. According to PHMSA, "[t]his could result in pipelines that are not monitored for internal corrosion, because an initial assessment did not identify the presence of corrosive gas." NPRM at 20,810. PHMSA also states that the agency issued an advisory bulletin on internal corrosion monitoring and evaluation in September 2000 following a gas transmission line incident in Carlsbad, New Mexico, and that operators reported 206 incidents attributable to internal corrosion between 2002 and 2012. NPRM at 20,810.

While INGAA recognizes that internal corrosion can have a detrimental effect on a pipeline, the entirety of the proposed regulation is neither necessary nor appropriate. As explained in INGAA's January 2012 comment letter in this proceeding,[187] onshore gas transmission operators are already taking comprehensive steps to address internal corrosion under Subparts I and O of the current regulations. PHMSA's regulations issued after the Carlsbad incident added design and construction standards for managing internal corrosion.[188] The NPRM fails to acknowledge the positive safety impacts of these regulations on reducing

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[187] INGAA, Comments on ANPRM (Jan. 20, 2012).

[188] Pipeline Safety: Design and Construction Standards To Reduce Internal Corrosion in Gas Transmission Pipelines, 72 Fed. Reg. 20,055 (Apr. 23, 2007).

incidents attributable to internal corrosion. In addition, industry follows guidance standards, such as NACE SP0106 – 2006 – Control of Internal Corrosion in Steel Pipelines and Piping Systems, which provide specific measures to manage internal corrosion.

The number of gas transmission line incidents attributable to internal corrosion is steadily declining. INGAA cannot determine how PHMSA derived the statistic cited in the NPRM of 206 incidents attributable to internal corrosion from 2002 to 2012. INGAA's review of PHMSA incident reports shows that there were 68 reported internal corrosion-related incidents in non-HCAs during the same time period. The solutions proposed in the NPRM would have had a minimal effect in preventing any of the 68 incidents because the cause of the internal corrosion would not have been addressed by the proposed regulation. For these reasons, PHMSA should eliminate proposed § 192.478 from the final rule.

If PHMSA retains proposed § 192.478, the final rule must provide clarification to address technical inaccuracies and eliminate duplicative requirements. Many of the potentially corrosive constituents listed in the proposal, e.g., carbon dioxide, sulfur, and hydrogen sulfide, are not corrosive in and of themselves. Liquid water or another electrolyte must be present before these constituents can have a potentially corrosive effect. Similarly, the partial pressure calculations required by the proposed rule for some of the potentially corrosive constituents (*e.g.*, sulfur, microbes, and free water) technically cannot be calculated. In addition, the generic reference to microbes is overbroad, because some types of microbes do not cause or contribute to internal corrosion. INGAA's recommended revisions to the proposed regulatory text clarify these points. Failure to make these clarifications would render proposed § 192.478 inconsistent with NACE SP0106-2006 Appendices B and C, which address impurities.

Proposed § 192.478(b)(1) fails to provide meaningful parameters for the term "gas-quality monitoring equipment." Nor does the NPRM preamble shed any light on this. NPRM at 20,810. The proposed rule could be interpreted to require continuous monitoring of the gas stream for potentially corrosive contaminants, which is not practicable or feasible, particularly for microbes for which no continuous monitoring equipment exists. The proposed regulation also lists "product sampling" as a mitigation measure in paragraph (b)(2) instead of as a monitoring technique in paragraph (b)(1). These shortcomings must be clarified in the final rule.

The internal corrosion monitoring requirement proposed in § 192.478(c) is identical to the requirement in existing § 192.477. The NPRM provides no basis for including redundant regulations. Proposed § 192.478(c) should be withdrawn to avoid unnecessary confusion.

PHMSA also offers no technical support for the biannual program review requirement in proposed § 192.478(d). NPRM at 20,830. Requiring reviews at this interval is unnecessary and excessive, particularly for pipeline systems that are not susceptible to internal corrosion (e.g., dry gas systems). Mitigation of internal corrosion is necessary only if a pipeline is transporting or has the potential to transport corrosive gas. Requiring mitigation measures for systems that do

not contain potentially corrosive constituents would be unnecessary, impracticable, and costly. PHMSA should eliminate § 192.478(d) from the final rule.

B. § 192.935 What Additional Preventive and Mitigative Measures Must an Operator Take?

Proposed § 192.935 requires an operator to take measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in an HCA. NPRM at 20,846. PHMSA justifies the additional internal corrosion measures on the basis that the current requirements are "non-specific." NPRM at 20,784.

Proposed § 192.935(f)(2), for example, would require use of "continuous gas quality monitoring equipment" at "points where gas with potentially deleterious contaminants enters the pipeline." The requirement to implement this and other prescriptive measures under §§ 192.935(a) and (f) is not limited to pipelines with an identified threat of internal corrosion, and does not grant the operator the flexibility to prioritize higher risk pipeline segments or to exclude those pipeline segments where internal corrosion is not a threat. PHMSA has not demonstrated why all pipelines in HCAs "must take additional measures beyond those already required by Part 192."[189] The proposal is inconsistent with section 5.1.2 of NACE SP0106-2006, which provides that, if the product transported is not corrosive, certain considerations may be "rejected." Given the compliance cost and the limited benefits that will result from these changes, the NPRM's blanket assertion that such enhancements have "benefit" is insufficient to justify the need for the proposed revisions.

1. Section 192.935(f) Should Be Modified to Permit Operators to Tailor Internal Corrosion Preventive and Mitigation Measures Based on the Operational Characteristics of a Specific Pipe Segment

Proposed § 192.935(f) establishes several prescriptive measures intended to enhance an operators internal corrosion program on a covered segment. INGAA agrees that operators should continually enhance their internal corrosion programs, but it recommends that operators be permitted to implement measures uniquely designed to eliminate the root causes of a potentially corrosive environment on each pipeline segment. Appropriate preventive and mitigative measures will vary significantly depending on the source of gas and the operating parameters of the pipeline. Requiring operators to implement the complete list of measures proposed in § 192.935(f) would compel operators to expend resources on activities that would not achieve any incremental safety benefit. Rather, operators should be permitted to manage internal corrosion using one or more methods identified by an operator as effective based on the unique factors of its affected pipeline.

[189] Proposed § 192.935(a).

PHMSA has failed to provide a technical explanation or justification for adding more strenuous and prescriptive internal corrosion measures for pipelines in HCAs. In proposed § 192.935's preamble, PHMSA says it "has determined that some additional prescriptive preventive and mitigative measures are needed to assure that public safety is enhanced in HCAs and affords greater protections for HCAs." This proposed rule "would add specific enhanced measures for managing external corrosion and internal corrosion inside HCAs." NPRM at 20,819. PHMSA has failed to explain why this regulation must apply to all pipeline segments in HCAs, including those that do not have an identified threat of internal corrosion. No internal corrosion incidents in interstate and intrastate HCAs were reported to PHMSA from 2010-2015.[190] The NPRM also fails to acknowledge that in April 2007, PHMSA added new subsection § 192.143 and expanded § 192.476 to address design and construction standards for managing internal corrosion.[191] The resources required to comply with the proposed § 192.935 would more effectively be deployed to reduce other risks.

When issuing a final rule, PHMSA is required to "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'"[192] Given the empirical data, PHMSA cannot justify any assertion that the current § 192.935 is inadequate and requires additional specificity "to establish a more effective minimum standard for internal corrosion management." NPRM at 20,784.

In addition to the current internal corrosion regulations, the NPRM fails to acknowledge that pipelines already manage internal corrosion by monitoring gas quality specifications at comingling points, installing filter separators and dehydrators at key system input points, and blending wet gas with dry gas. The NPRM does not acknowledge that interstate natural gas pipelines must have gas quality specifications in their FERC-approved tariffs.[193] Pipelines typically monitor the quality of gas entering their systems at key receipt points where smaller, lower volume lines connect. This ensures that gas is blended sufficiently to meet the gas quality specifications set forth in each pipeline's tariff. Operators monitor gas quality at smaller-volume receipt points and other points by conducting periodic manual sampling. Operators post gas quality data for key locations representing mainline gas flow on their websites, as required

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[190] This statement is based on the analysis of the PHMSA Incident Reports at http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

[191] Pipeline Safety: Design and Construction Standards to Reduce Internal Corrosion in Gas Transmission Pipelines, 72 Fed. Reg. 20,055, 20,059 (Apr. 23, 2007).

[192] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines v. United States*, 371 U.S. 156, 168 (1962)) (vacating as arbitrary and capricious final rule that rescinded regulations without adequate explanation).

[193] *Indicated Shippers v. Trunkline Gas Co. LLC*, 105 FERC ¶ 61,394, at P 15 (2003) ("Gas quality standards are practices of the pipelines and operational conditions and must be included in the pipelines' tariffs.") (internal citations omitted).

under their FERC tariffs. The effectiveness of these methods are reflected in the reduced number of incidents attributed to internal corrosion.

Since issuing the NPRM, PHMSA has made several statements undercutting the stated need for the broad-based proposed measures. PHMSA acknowledged that the proposed requirement to use cleaning pigs and sample accumulated liquids and solids, including tests for microbiologically induced corrosion, is not applicable to dry gas systems. This contradicts the proposed regulation, which would require all operators in HCAs, including those operating dry gas systems, to comply with all of the listed measures in proposed § 192.935(f).

PHMSA has failed to demonstrate that the added cost of implementing every preventive and mitigative measure in § 192.935(f) would provide corresponding safety benefits when compared with allowing operators to implement preventive and mitigative measures in the most appropriate way based on the operating history and risk profile of each system or segment. Installing continuous monitoring systems at each pipeline receipt point "where gas with potentially deleterious contaminants enters the pipelines" is unnecessary and costly. Each continuous monitoring system would include a gas chromatograph, moisture analyzer, and sulfur analyzer, costing a total of approximately $250,000 at each point. A single pipeline may have hundreds of receipt points. If continuous monitoring systems were installed on a pipeline with just 100 locations, that pipeline's cost to install would be $25 million. There are 153 interstate pipelines. If each pipeline has at least 100 receipt points, then the industry-wide cost of implementing this provision would be well over $1 billion. These costs are not accounted for in the PRIA which erroneously asserts that "the added costs of monitoring . . . is either nothing or relatively inexpensive."[194] The PRIA represents the entire cost for all of industry as $400,000.[195] These costs are not commensurate with the negligible safety benefits relating to internal corrosion. PHMSA has not demonstrated why its proposed changes would improve safety.

PHMSA has not made a rational connection between the facts found and the choice made.[196] PHMSA's authority to issue safety standards also is constrained by the PSA, which requires that a safety standard be "practicable" and designed to meet gas pipeline safety needs and protect the environment.[197] When prescribing any safety standard, PHMSA must consider relevant available gas pipeline safety information, environmental information, the appropriateness of the standard for the type of transportation or facility and reasonableness.[198]

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[194] PRIA at 90, § 3.4.4.4.

[195] PRIA at 91, § 3.4.4.4, Table 3-75 The stated cost in the PRIA is less than what it may cost an individual pipeline to implement this aspect of the regulation.

[196] *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 839, 843 (D.C. Cir. 2006); *Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

[197] 49 U.S.C. § 60102(b)(1).

[198] 49 U.S.C. § 60102(b)(2).

For these reasons, INGAA proposes that § 192.935(f) apply only to pipeline segments with a history of internal corrosion, consistent with the required risk analysis that is performed to determine whether preventive and mitigative measures are necessary. The proposed measure should not apply to all pipelines segments in an HCA. In addition, proposed § 192.935(f) must permit operators to tailor appropriate preventive and mitigative measures based on a risk assessment and the specific characteristics of an individual pipeline segment. INGAA's proposal promotes the continual improvement of integrity management in a cost-effective manner that is consistent with the requirements of the PSA.

C. INGAA's Proposed Regulatory Text Relating to Internal Corrosion

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

(a) For non-dry gas onshore transmission pipelines, each operator must develop and implement a monitoring and mitigation program to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects. Potentially corrosive constituents include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and ~~free~~ liquid water, either by itself or in combination. Each operator must evaluate the partial pressure of each corrosive constituent (where applicable) by itself or in combination to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures.

~~(b) The monitoring and mitigation program in paragraph (a) of this section should consider methods such as:~~

~~(1) Gas quality monitoring at points where gas with potentially corrosive contaminants enters the pipeline, to determine the gas stream constituents;~~

~~(2) Options such as product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents where corrosive gas is being transported;~~

~~(3) Evaluation each calendar year, at intervals not to exceed 15 months, of gas stream and liquid quality samples and implementation of adjustments and mitigative measures to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated where corrosive gas is being transported.~~

~~(c) If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked at least twice each calendar year, at intervals not exceeding 7 ½ months.~~

~~(d) Each operator must review its monitoring and mitigation program at least twice each calendar year, at intervals not to exceed 7 ½ months, based on the results of its gas stream sampling and internal corrosion monitoring in (a) and (b) and implement adjustments in its monitoring for and mitigation of the potential for internal corrosion due to the presence of potentially corrosive gas stream constituents.~~

§ 192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. ~~An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to,~~ Such additional measures must be based on the risk analyses required by § 192.917, and ~~must~~ may include, but are not limited to:

[…]

(f) *Internal corrosion*. For segments with an identified internal corrosion threat, ~~As~~ an operator ~~gains information about internal corrosion, it~~ must enhance its internal corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to internal corrosion. At a minimum, as part of this enhancement, operators ~~must~~ should, based on a risk analysis for the pipeline segment, consider implementing any of the following ~~must—~~

(1) Monitor for, and mitigate the presence of, deleterious gas stream constituents.

(2) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators ~~and~~ or continuous gas quality monitoring equipment, or take other appropriate steps to mitigate the risk associated with deleterious contaminants.

(3) At least once per quarter, use gas quality monitoring equipment that may include~~s~~, ~~but is not limited to,~~ a moisture analyzer, chromatograph, carbon dioxide sampling, ~~and~~ or hydrogen sulfide sampling.

(4) Use cleaning pigs and sample accumulated liquids and solids, including tests for microbiologically induced corrosion.

(5) Use inhibitors when corrosive gas or corrosive liquids are present.

~~(6) Address potentially corrosive gas stream constituents as specified in § 192.478(a), where the volumes exceed these amounts over a 24-hour interval in the pipeline as follows:~~

~~(i) Limit carbon dioxide to three percent by volume;~~

~~(ii) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and~~

~~(iii) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas. If the hydrogen sulfide concentration is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.~~

(7) Review the program at least semi-annually based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.

This would achieve what the rule is intended to address by allowing operators to target pipe that is at risk due the manufacturing and construction defects.

5. Other Non-Substantive Changes

Finally, INGAA is proposing several changes to subsection (e) that remove potentially confusing redundancies or inaccuracies. This includes but is not limited to:

> (1) deletion of reference to §192.624(c) from subpart (e)(3), because it is inapplicable and already addressed by other requirements of the safety rules;
> (2) deletion of reference to "pipe body cracking" from subpart (e)(4), because this is already covered by subpart (e)(3);
> (3) deletion of the reference to §192.605(c) in subpart (e)(4), because it is not clear how it is applicable; and
> (4) deletion of reference to §192.624(c) and (d) in subpart (e)(4), because §192.624(c) is inapplicable (applies to MAOP, rather than fracture crack growth analysis) and §192.624(d) is already addressed in the rules for assessing seam integrity and seam corrosion anomalies.

INGAA's proposal would provide additional clarity which will ensure that the new safety rules are clearly understood and can be effectively implemented by the operators.

C. Proposed Section 192.921

Existing Section 192.921 addresses the methods for conducting baseline assessments. The preamble to the NPRM states that the intent of the proposed changes to Section 192.921 is to require the use of in-line inspection and pressure testing over direct assessment (DA). NPRM at 20,817. The rule would also add three additional assessment methods, each of which the proposed rule considers preferable to DA, including spike hydrostatic pressure testing. INGAA is proposing changes the will ensure that operators have the flexibility to use the most appropriate assessment methodology for a given pipeline condition.

1. Direct Assessment - Proposed Section 192.921 (a)(6)

The NPRM's proposed changes to § 192.921(a)(6) would limit the use of direct assessment to pipeline segments that cannot be assessed using in-line inspection tools and are "not practical" to assess using a subpart J pressure test, a "spike" hydrotest in accordance with § 192.506, excavation and *in situ* direct examination, or guided wave ultrasonic testing. The NPRM does not provide any data or technical justification for the proposed changes to §

192.921. It simply points to an NTSB Recommendation,[235] cites "ongoing research" without identifying or discussing said research,[236] and explains that, "At San Bruno, PG&E relied heavily on direct assessment under circumstances for which direct assessment was not effective.[…] Therefore, the proposed rule would require that direct assessment only be allowed when the pipeline cannot be assessed using in-line inspection tools." The NPRM neglects to address the fact that the San Bruno pipeline did not fail due to a corrosion anomaly, but rather due to an unstable manufacturing-related defect that had never been hydrostatically tested. DA is not an applicable assessment method for this type of defect. The San Bruno incident provides no justification for the NPRM's proposed changes to the requirements surrounding the use of direct assessment for corrosion threats.

The NPRM gives contradictory descriptions of the industry to the ANPRM, which overwhelmingly supported allowing operator flexibility in selecting effective assessment techniques.[237] Despite this, the NPRM states that industry response to the ANPRM "appear[s] to indicate that ILI and spike hydrostatic pressure testing is more effective than DA for identifying pipe conditions that are related to stress corrosion cracking defects." NPRM at p. 20,727.

INGAA is proposing that the criteria for when direct assessment can be used should depend on whether direct assessment can provide the necessary information about the pipe condition, and not whether other assessment methods are possible.

DA is a thorough, four-step process. DA is a technically-based assessment method that provides a valuable assessment method for operators in the safe operation of natural gas pipelines. The industry standard for integrity management, ASME B31.8S-2004, which is

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[235] The proposed changes to this rule are designed to address one of the NTSB Recommendations from its 2015 Safety Study, "Integrity Management of Gas Transmission Pipelines in High Consequence Areas." Recommendation P-15-21 was for PHMSA to "[d]evelop and implement a plan for eliminating the use of direct assessment as the sole integrity assessment method for gas transmission pipelines."

[236] NPRM at p. 20,817

[237] *See* 68 Fed. Reg. 20722, at 20770-20771. ANPRM question G.2 asked "*Should the regulations require assessment using ILI whenever possible, since that method appears to provide the most information about pipeline conditions? Should restrictions on the use of assessment technologies other than ILI be strengthened? If so, in what respect? Should PHMSA prescribe or develop voluntary ILI tool types for conducting integrity assessments for specific threats such as corrosion metal loss, dents and other mechanical damage, longitudinal seam quality, SCC, or other attributes?*" Comments from various industry stakeholders, including trade organizations, pipeline operators, and standard-setting bodies, consistently supported the continued use of all assessment techniques without overly prescriptive limitations, in order to allow operators the flexibility to use engineering judgment to evaluate identified threats. Several commenters also noted that direct assessment is more appropriate for some threats, and that the operator is ultimately responsible for ensuring the threats on its pipelines are assessed. In fact, only one commenter, the California Public Utilities Commission, was noted by the NPRM suggesting that the use of DA should be limited.

incorporated by reference into the existing § 192.921, describes DA as "an integrity assessment method utilizing a structured process through which the operator is able to integrate knowledge of the physical characteristics and operating history of a pipeline system or segment with the results of inspection, examination, and evaluation, in order to determine the integrity."[238] Existing regulations §§ 192.923, 192.925, 192.927, and 192.929 govern the use of direct assessment and specify which threats it may be used to assess. Specifically, DA can only be used for external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA), and stress corrosion cracking (SCC) direct assessment (SCCDA) and are only appropriate for assessing the threats of those specific types of corrosion on a pipeline segment.

DA is used to identify locations where corrosion defects may have formed. The first of four steps requires the operator to evaluate and demonstrate the feasibility of DA to the location given the specific circumstances. The DA process integrates facilities data, current and historical field inspections and tests with the physical characteristics of a pipeline through a four-step process. Indirect examinations are used to monitor the adequacy of a pipeline's corrosion protection program, as well as coating integrity. The DA process also requires excavations, which confirm the ability of the indirect examinations to detect locations on the pipeline where active corrosion may be present and areas of significant coating damage at which corrosion could occur. The excavations also identify locations requiring remediation. A post-assessment step is required to determine the corrosion rate, set the re-inspection interval, reassess the performance of remediation measures and their continued applicability, and ensure the assumptions made in the previous steps remain correct, or where applicable, are adjusted.

INGAA proposes to clarify the way in which SCCDA can be used as an integrity assessment method. SCCDA is a valid way to assess for the SCC threat in gas pipelines for segments that are susceptible to SCC but have no history of SCC.[239] NACE has developed and periodically updated a standard practice for SCCDA, with the most recent version published in 2015.[240] SCCDA is a process that has been validated through round-robin testing. When there is a history of SCC, then an ILI or pressure spike test should be used.[241]

INGAA's proposal recognizes when to use particular assessment methods by allowing operators the flexibility to continue to utilize direct assessment when it can provide the necessary information about the pipe condition. For these reasons, PHMSA should adopt INGAA's proposed changes to Section 192.921(a)(6) of the NPRM, which are included below.

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[238] ASME/ANSI B31.8S at 19.

[239] ASME B31.8S (2012), Appendix A, Section 3.4.4 and Table A-3.4.1-1p. 51-52.

[240] NACE SP 0204 – 2015, Stress Corrosion Cracking (SCC) Direct Assessment Methodology.

[241] *Id.* at p. 51.

using ILI.[248] By contrast, a reading of the proposed rule itself reveals that operators would only be allowed to use DA when ILI is not possible and hydrostatic pressure testing, spike testing, GWUT, and excavation are not practical. Based on its mischaracterization of the rule, the PRIA concludes that this aspect of the proposed rule "would not impose a significant additional cost burden on pipeline operators." This conclusory statement is not supported, and does not consider the additional cost burden of requiring other costly assessment methods to be used when practical.

With respect to the additional assessment methods of spike pressure testing, GWUT, and excavation with *in situ* examination, the PRIA states: "All of these assessment methods are implicitly allowed by existing requirements; the proposed rule would not mandate use."[249] However, on lines that previously were allowed to be assessed for corrosion threats using DA, the proposed rule *does* mandate that they be used when practical, and the PRIA fails to include this additional cost burden.

Finally, the PRIA does not consider the costs of the effects of spike hydrostatic testing. Spike hydrostatic testing can cause damage to pipeline coating and can cause failures on pipe that would survive normal operating conditions or a Subpart J test. Not only has PHMSA failed to consider the cost to operators of conducting these tests, but also has failed to consider the costs of repairs to coating and pipe replacement for these segments that fail an unnecessary and overly burdensome spike test. For these reasons, PHMSA's PRIA fails to properly assess the significant cost on operators that will result from the proposed changes to Section 192.921, which are not commensurate safety benefits.

D. INGAA's Proposed Regulatory Text.

§ 192.506 Transmission lines: Spike hydrostatic pressure test for existing steel pipe with integrity threats.

(a) Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and has been found to have time-dependent cracking, including stress corrosion cracking ~~integrity threats that cannot be addressed by other means such as in-line inspection or direct assessment~~ must be strength tested by a spike hydrostatic pressure test in accordance with this section to substantiate the proposed maximum allowable operating pressure.

(b) The spike hydrostatic pressure test must use water as the test medium.

[248] PRIA at p. 71 ("DA is typically not chosen as the assessment method if the pipeline can be assessed using ILI.")
[249] *Id.* at 72.

[…]

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

[…]

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading conditions (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. ~~An~~The evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment. ~~Fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis must be conducted in accordance with § 192.624(d) for cracks.~~ Cyclic fatigue analysis must be ~~annually, not to exceed 15 months~~ conducted periodically, not to exceed seven (7) calendar years.

(3) *Manufacturing and construction defects.* ~~If an operator identifies the threat of~~ An operator must analyze the covered segment to determine the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment according to the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A5.3. ~~an operator must analyze the covered segment to determine the risk of failure from these defects.~~ The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to a hydrostatic pressure testing satisfying the criteria of subpart J of this part of at least 1.25 times MAOP, and the segment has not experienced an in-service incident attributed to a manufacturing or construction defect since the date of the pressure test. ~~operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area.~~ If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment~~, and must reconfirm or reestablish MAOP in accordance with §192.624(c)~~.

(i) ~~Operating pressure increases above the maximum operating pressure experienced during the preceding five years;~~ The segment has experienced an in-service incident as described in §192.624(a)(1).

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe, pipe with seam factor less than 1.0 as defined in §192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including but not limited to ~~pipe body cracking,~~ seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years ~~(including abnormal operation as defined in §192.605(c))~~, or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment. ~~Pipe with cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 192.624(c) and (d).~~

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of line pipe in each covered segment by applying one or more of the following methods ~~depending on the~~ for each threat~~s~~ to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917). In addition, an operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

(1) Internal inspection tool or tools capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. ~~An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment~~. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. ~~A person qualified by knowledge, training, and experience~~ An operator must analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

[…]

(3) "Spike" hydrostatic pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for threats such as stress corrosion cracking~~, selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects~~;

[…]

(6~~3~~) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of external corrosion direct assessment and internal corrosion direct assessment is allowed only if the line is not capable inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (d)(5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with~~, as~~ the applicable, the requirements specified in §§ 192.925, 192.927 or 192.929; or

4.4. Interference Current Surveys

Proposed section 192.473(c) would require interference current surveys if stray current are found in HCAs. Proposed section 192.935(g)(1) would require periodic surveys whenever needed, but not to exceed every seven years. For simplicity, PHMSA assumed a seven-year survey interval for the periodic requirement in section 192.473(c).

PHMSA estimates the costs of these ICS requirements at $1.8 million. However, PHMSA does not include several cost drivers of the proposed requirements and inappropriately applies a compliance factor. PHMSA does not consider any of the costs of remediation of AC stray current to excessively conservative current density criteria in its cost estimates. Industry consensus standards consider AC densities 100 A/m^2 to be corrosive and uncertain range to be between 30 A/m^2 and 100 A/m^2. PHMSA's prescriptive criteria of 20 and 50 A/m^2 are not supported by research and experience.

For calculation purposes, INGAA's cost estimates utilize the incremental need for survey rate reported in Table 3-74 of the PRIA. As shown at Table 50 in Attachment 6, Section 4.4, INGAA estimates the costs of the ICS rules to be approximately $6 million, far in excess of PHMSA's estimated cost of approximately $1.8 million.[332]

4.5. Internal Corrosion Monitoring

Proposed section 192.478 includes new requirements to address internal corrosion, including evaluating the partial pressure of corrosive constituents, use of gas-quality monitoring equipment, and semi-annual evaluations of gas quality and semi-annual monitoring and mitigation program evaluations. Proposed section 192.935(f) provides a lengthy list of requirements for addressing internal corrosion in HCAs. PHMSA proposes that operators install continuous monitoring systems at each pipeline receipt point "where gas with potentially deleterious contaminants enters the pipelines."

The proposed rule would require internal corrosion monitoring for carbon dioxide, hydrogen sulfide, sulfur, microbes, water and other corrosive constituents. The PRIA states that the entire cost of this requirement would be "either nothing or relatively inexpensive,"[333] and, based on a cost of $10,000 for each monitoring system, estimates this cost at $400,000 for all of the industry.[334]

[332] *See* Attachment 6, Table 49 at row 3.

[333] PRIA § 3.4.4.4.

[334] *Id.* at § 3.4.4.5.

This is an unreasonable underestimation of the costs of this requirement. Each continuous monitoring system would cost approximately $275,000, and an individual pipeline may have over one thousand receipt points. In addition, the current compliance rates are not applicable. Therefore, INGAA calculates the costs using the total number of monitors needed according to PHMSA, without applying the compliance factor. INGAA's cost calculations for the proposed internal corrosion monitoring requirements far exceed PHMSA's estimates. While PHMSA estimates total costs only at $400,000, INGAA has calculated that these costs will amount to a $75.5 million one-time cost.[335]

4.6. Other Uncaptured Costs

Proposed changes to the corrosion control requirements in the NPRM will mandate additional costs for a number of items that are not captured, including:

- Changes to prompt remedial action timeframes in HCAs and outside HCAs
- Semi-annual internal corrosion monitoring and mitigation program reviews
- Data integration
- Cost of documenting compliance to the additional requirements

INGAA did not have time to estimate total costs of these items. INGAA notes, however, that these costs will be significant, and that PHMSA has further underestimated costs of its proposed corrosion control requirements by ignoring these costs completely. As demonstrated by Tables 49 and 50 of Attachment 6, PHMSA has disregarded several costs of its proposed corrosion compliance requirements, and underestimated the total costs of its proposed standards by at least $664 million annually.

➢ **Additional Costs Associated with FERC Regulation**

PHMSA does not account in the PRIA for its requirements' triggering of additional costs of compliance with FERC requirements. The PRIA ignores that FERC requires interstate natural gas pipelines to provide demand charge credits to customers when firm transportation services are disrupted, including when the disruption is caused by testing and repairs. Given the scope of the proposed rule, the potential for pipelines to incur demand charge credits is likely to be substantial. Gas drawdowns required for MAOP testing in compliance with section 192.624 will extend the duration of outages and service interruption, further adding to these costs. The Proposed Rule also fails to consider that FERC approval may be necessary if, as a result of the NPRM, a pipeline has to alter, improve, or remove from service pipeline facilities. If FERC does not permit a pipeline to abandon facilities that cannot be brought up to the new

[335] *See* Attachment 6, Table 49 at row 4.

Based on this assessment, PHMSA concludes that these effects would be negligible because the impacts are expected to be localized within the existing right-of-way, temporary in duration, and decrease the likelihood of catastrophic damage due to pipeline failure.[400] PHMSA's EA also addresses environmental justice concerns, greenhouse gas emissions, public safety, and public health in a similarly perfunctory fashion.[401]

Because PHMSA's EA provides only general statements about possible effects without actually analyzing the proposed alternative, it does not comply with the "hard look" standard. For example, the EA notes that there could be impacts to wetlands, rivers, historic resources, and farmland.[402] While PHMSA is required to consider these types of resources as part of its consideration of intensity of the action,[403] the EA merely identifies the specified characteristic and provides a conclusory statement regarding the magnitude of impact without any detail, supporting analysis or evaluation.[404] This approach precludes any ability to determine the significance of the action because there is a dearth of information upon which to base such a conclusion.[405]

C. Consideration of Indirect Effects

In addition to direct effects, the EA must also consider indirect effects of the action. Indirect effects are defined as those "which are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable."[406] These effects may include

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[400] PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 14-15 (Mar. 21, 2016).

[401] PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 15-18 (Mar. 21, 2016). INGAA notes that in two instances PHMSA attempts to provide actual data—estimating the potential reduction of greenhouse gas emissions and the reduction of fatalities. PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 15-16 (Mar. 21, 2016). Given the perfunctory treatment of these analyses, it is unclear what factors PHMSA considered in quantifying these effects and whether the scope of these analyses fully contemplated all components of the proposed rule.

[402] While Draft EA also identifies potential impacts to terrestrial species, there is no discussion of species or crucial habitat under the Endangered Species Act.

[403] 40 C.F.R. § 1508.27(b)(3).

[404] If PHMSA lacks the data to properly consider these effects, its failure to properly acknowledge and address the many gaps in its environmental risk analysis is in itself a NEPA violation. PHMSA is required to "always make clear" when there is "incomplete and unavailable information." 40 C.F.R. § 1502.22; *Lands Council v. Powell*, 395 F.3d 1019, 1033 (9th Cir. 2005) (NEPA "requires up-front disclosures of relevant shortcomings in the data or models.").

[405] *Sierra Club v. Mainella*, 459 F. Supp. 2d 76, 108 (D.D.C. 2006) (Agency's failure to take a "hard look" was evidenced by the "lack of explanations supporting its conclusions and, in particular, its methodology of describing impacts using conclusory labels and then setting forth a bare conclusion without explanation as to the significance of an impact.").

[406] 40 C.F.R. § 1508.8(b); *Barnes v. U.S. Dep't of Transp.*, 655 F.3d 1124, 1136 (9th Cir. 2011) ("While 'foreseeing the unforeseeable' is not required, an agency must use its best efforts to find out all that it reasonably can.")

"growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems."[407]

The EA is deficient because it fails to include any discussion of indirect effects associated with the proposed action.

D. Failure to Consider Cumulative Effects

PHMSA is required to consider the cumulative effects of the proposed action. Cumulative effects are defined as "the impact on the environment which results from the incremental impacts of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (federal or non-federal) or person undertakes such other actions. Cumulative impacts "can result from individually minor but collectively significant actions taking place over a period of time."[408] Courts have consistently held that NEPA's cumulative effects requirements apply to EAs as well as EISs.[409] The D.C. Circuit has explained that:

> a meaningful cumulative impact analysis must identify (1) the area in which the effects of the proposed project will be felt; (2) the impacts that are expected in that area from the proposed project; (3) other actions—past, present, and proposed, and reasonably foreseeable—that have had or are expected to have impacts in the same area; (4) the impacts or expected impacts from these other actions; and (5) the overall impact that can be expected if the individual impacts are allowed to accumulate.[410]

PHMSA's EA does not include a cumulative effects analysis nor does it attempt to provide any insight into the past, present, and reasonably foreseeable actions that would help portray a "realistic evaluation of the total impacts" of the proposed action. On the contrary, when evaluating the various elements of the preferred alternative that could lead to more excavations, PHMSA repeatedly states that each proposed component would "individually have

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(citation omitted).

[407] 40 C.F.R. § 1508.8(b).

[408] 40 C.F.R. § 1508.7.

[409] *See Kern v. U.S. Bureau of Land Mgmt.*, 284 F.3d 1062, 1076 (9th Cir. 2002) ("[A]n EA may be deficient if it fails to include a cumulative impact analysis or to tier to an EIS that has conducted such an analysis."); *Grand Canyon Trust v. FAA*, 290 F.3d 339, 342 (D.C. Cir. 2002) (as amended) ("the consistent position in the case law is that, depending on the environmental concern at issue, the agency's EA must give a realistic evaluation of the total impacts and cannot isolate a proposed project, viewing it in a vacuum.").

[410] *Del. Riverkeeper Network v. FERC*, 753 F.3d 1304, 1319 (D.C. Cir. 2014) (quoting *Grand Canyon Trust v. FAA*, 290 F.3d 339, 345 (D.C. Cir. 2002)

minor localized environmental impacts."[411] By explicitly stating that it only considered effects "individually" and in a "localized" area, PHMSA has failed to conduct the requisite cumulative effects analysis. Instead, PHMSA violated NEPA by only considering these effects of its preferred alternative in a vacuum. Before promulgating any final rule, PHMSA must assess the totality of impacts from both its proposed action and those other actions that are reasonably foreseeable.

E. The Consideration of Climate Change is Deficient

Courts have found that an agency has a duty to assess "the effects of *its* actions on global warming within the context of other actions that also affect global warming."[412] Based upon guidance from the Council on Environmental Quality, PHMSA "should consider the following . . . : (1) the potential effects of a proposed action on climate change as indicated by its GHG emissions; and (2) the implications of climate change for the environmental effects of a proposed action."[413]

While PHMSA notes that the proposed rule may result in fewer accidents or incidents which could reduce the emission of GHGs,[414] the EA fails to consider that the proposed rule will also cause an increase in GHG emissions.

[411] PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 15-18 (Mar. 21, 2016) (in some places, PMSA states that the excavations would "individually have very minor and localized environmental impacts").

[412] *Ctr. for Biological Diversity v. Nat'l Hwy. Traffic Safety Admin.*, 538 F.3d 1172, 1217 (9th Cir. 2008) (requiring agency to examine effects associated with greenhouse gas emissions resulting from the promulgation of corporate average fuel economy standards for light trucks).

[413] Revised Draft Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in NEPA Reviews, 79 Fed. Reg. 77,802, 77,824 (Dec. 24, 2014).

[414] PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 15 (Mar. 21, 2016).

Safety of Gas Transmission Pipeline Rule

Cost Analysis

A Review of the Natural Gas
Notice of Proposed Rulemaking (NPRM) and
Preliminary Regulatory Impact Analysis (PRIA)

Interstate Natural Gas Association of America
(INGAA)

July 7, 2016

4.0 Topic 4: Corrosion

The NPRM proposes new regulations and changes to existing regulations in the following areas:

1. Coating condition survey requirements [192.319(d), 461(f) and 935(g)(2)(ii)]
2. Close-interval survey requirements [192.465(f) and 935(g)(2)(iv)(A)]
3. Requirements for test lead spacing in high-consequence areas [192.935(g)(2)(iv)(B)]
4. Requirements for interference surveys [192.473(c)(1) and 935(g)(1)(i)(A)]
5. Gas quality monitoring [192.478(a) and 935(f)(2)]

4.1 External Corrosion Coating

The proposed rule would require coating surveys when an operator does a repair with an excavation of 200 feet or more. Compared to PHMSA, operators estimate 2,500 surveys will result from the requirement compared to 240 reported by PHMSA. In addition, the cost per survey averages to be $3,000, regardless of class location. The costs for coating surveys are outlined in **Table 44**.

Table 44: External Corrosion Coating Survey Cost

Element	Operator reported # of Coating Survey Miles	Cost of Survey per Mile (Avg.)	Total Survey Cost	Anomalies per Mile	Total Anomalies	Low Cost to Repair	High Cost to Repair	Average Cost to Repair	Total
New Construction	2000	$3,000	$6,000,000	2	4000	$25,000	$50,000	$37,500	$150,000,000
Repair/Replacement >than 1,000 feet	500	$3,000	$1,500,000	2	1000	$25,000	$50,000	$37,500	$37,500,000
Every 7 years in HCA	2,832	$3,000	$8,496,000	6	16992	$25,000	$50,000	$37,500	$637,200,000
Total			**$15,996,000**						**$824,700,000**
							Total Cost		**$840,696,000**

Source: Operator Data

4.2 External Corrosion Monitoring CIS

The proposed rule would require CIS when a test station reading indicates low cathodic protection (CP). CIS would be required in both directions of a test station. Industry assumes that in total one-mile would need surveying once an out of compliance is located. Industry also questions the .5 % out of compliance rate reported in the RIA. Based on operator survey data industry assumes that 1 percent of test stations would be out of compliance. In addition, CIS would be required in HCAs every 7 years, which

seems to unaccounted for in the PHMSA RIA. Industry does not agree with the current compliance rates indicated in the RIA. **Table 45** shows the total CIS survey cost.

Table 45: External Corrosion CIS Survey Cost

Element	Mileage and # of Test Stations	Out of compliance	Average Survey Mile	Total Miles	Cost to CIS/Mile	Total Survey Cost
Test Stations along Pipeline	297,826	1%	1	2,978	$3000	$8,934,780
Every 7 years in HCA	2,832	-	1	2,832	$3000	$8,496,000
Resurvey Test Stations	2,978	-	1	2,978	$3,000	$8,934,000
Total						**$26,364,780**

Source: Operator Data

4.3 Cost of Adding Test Stations in HCAs

The proposed rule would require pipe-to-soil test stations be located at half-mile intervals within each HCA segment. Currently industry has a least one station within one-mile intervals. For cost development, industry is using the new station estimate of new station needed according to the RIA Table 3-73. The cost to add a test station reported by PHMSA at $500 is low compared to the industry average of $3,500 shown in **Table 46**.

Table 46: Cost to Add a Test Station in HCAs

HCA Miles	New Stations (PHMSA)	Cost per Station Low	Cost per Station High	Avg. Cost per Station	Total Station Cost
19,872	7,949	$2,500	$5,000	$3,750	$29,808,750
Total					**$29,808,750**

Source: Operator Data and RIA pg. 89

4.4 Interference Current Surveys

The proposed rule would require interference current surveys as proposed in 192.473(c) if stray current is found. Part 192.935 (g)(1) would require periodic surveys whenever needed, but not to exceed every 7 years. Compliance totals are shown in **Table 47**.

Table 47: Interference Current Surveys

HCA Miles	Cost to Survey	Incremental Need to Survey	Compliance Mileage	Total Cost
42,546[1]	$14,000	1%	425	$5,950,000
Total				**$5,950,000**

Source: Operator Data and RIA pg. 90

1. Mileage based on 1/7 of total mileage

4.5 Internal Corrosion Monitoring

The proposed rule would require interference internal corrosion monitoring for CO_2, sulfur, water and other chemicals. PHMSA reports that the cost for monitoring is relatively inexpensive.

PHMSA drastically underestimates monitoring equipment costs. **Table 48** outlines industry estimates for costs to add continuously monitoring equipment in HCA that range from $200,000 to $350,000. In addition, the current compliance rates are not applicable. Therefore, costs are calculated using the total number of monitors needed according to PHMSA without applying the compliance factor.

Table 48: Internal Corrosion Monitoring Cost

	Number of Monitors	Low Cost of Monitoring Equipment	High Cost of Monitoring Equipment	Average Cost of Monitoring Equipment	Total Cost
Continuous Monitoring Equipment HCA	**180**	$200,000	$350,000	$275,000	$49,500,000
Monitoring Equipment Non-HCA	**650**	$30,000	$50,000	$40,000	$26,000,000
	Total				**$75,500,000**

Source: Operator Data and RIA pg. 91

Table 49 is the total corrosion compliance cost compared to PHMSA costs. The totals are discounted based on different compliance schedules.

Table 49: Total Corrosion Compliance Cost

Component	Industry One-Time	Industry Annual	Industry Recurring (7 Years)	PHMSA One-Time Cost	PHMSA Annual	PHMSA Recurring (7 years)
External Corrosion Coating		$840,696,000		-	$298,000	
External Corrosion Monitoring	$29,808,750	$26,364,780		$3,974,492	$6,602,718	
Interference Current Surveys			$5,950,000			$1,829,877
Internal Corrosion Monitoring	$75,500,000	-		$400,000		
Total Cost	$105,308,750	$867,060,780	$5,950,000	$4,374,492	$6,900,718	$1,829,877
3% Discount	$105,308,750	$10,661,442,767	$73,161,635	$4,374,492	$84,851,733	$11,742,668
7% Discount	$105,308,750	$8,449,913,073	$57,985,534	$4,374,492	$67,250,726	$10,552,056

Source: PRIA and Operator Data
1. One-time cost in year 1; annual costs in years 1-15 years; and 7-year recurring costs annualized over 7 years.

The total present value for industry versus PHMSA costs are reflected in **Table 50**.

Table 50: Present Value Cost, Topic Area 4

	Total 7%	Average Annual (7%)	Total 3%	Average Annual (3%)
Industry Costs	$8,613,207,357	$672,501,990	$10,839,913,152	$820,949,043
PHMSA Costs	$94,788,018	$6,319,201	$118,451,243	$7,896,750

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Technology for Energy Pipelines

Basics of Metal Fatigue in Natural Gas Pipeline Systems — A Primer for Gas Pipeline Operators

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BASICS OF METAL FATIGUE IN NATURAL GAS PIPELINE SYSTEMS — A PRIMER FOR GAS PIPELINE OPERATORS

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INTRODUCTION

The natural gas pipeline industry is rapidly implementing comprehensive integrity management practices to meet the demands of new regulatory imperatives and public interests. These new demands require formal integrity management planning programs be developed and applied where pipeline failures could affect "High Consequence Areas". A formal integrity management plan (IMP) incorporates some process for identifying threats to a pipeline's integrity. Such threats come in many forms and are uniquely dependent on a wide range of attributes associated with an individual pipeline segment. Once such threats are identified, the pipeline operator must characterize the degree of risk associated with the threat as a means of prioritizing responses, identify suitable methods to assess the presence of the threat, and develop appropriate mitigations.

Interest (or concern) has arisen regarding metal fatigue as one such possible integrity threat. We know from some pipeline failures that occasionally and under certain circumstances, fatigue may constitute a potential threat. More to the point, 49 CFR Part 192, Subpart O, "Implementing Integrity Management", Paragraph 192.917(e)(2) requires an operator to address the threat of "cyclic fatigue". In order to meet the objectives and requirements of this rule, a pipeline operator must be able to discern what types of pipe or piping construction are susceptible to fatigue, what modes of pipeline operation or situations are conducive to fatigue, the consequences of a fatigue-related incident, and what actions could be taken to mitigate the threat. At the request of the Pipeline Research Council International (PRCI), the Gas Technology Institute (GTI), and the Interstate Natural Gas Association of America (INGAA) this review was undertaken to provide fundamental information to gas pipeline operators to enable them to address issues of fatigue as they pertain to natural gas pipelines. In so doing, the document will explore the questions "What is fatigue?", "Where can it occur in a gas pipeline facility?", and "What can be done about it?"

The cumulative body of knowledge derived by theory, test, and experience on the subject of fatigue and its effects on piping, pressurized equipment, and welded structures is vast in scope and detail, and it is not the intention of this document to summarize that. Rather, it is intended that this document provide natural gas pipeline operators and others interested in natural gas pipeline safety with a useful understanding of the extent to which fatigue could pose a legitimate and actionable safety threat, as well as to demonstrate the authors' opinion that in most respects, fatigue remains a comparatively minor risk component of the overall spectrum of threats to natural gas pipeline safety.

FATIGUE FUNDAMENTALS AND CONCEPTS

What is Fatigue?

Fatigue is a process of structural degradation caused by fluctuations or cycles of stress or strain. Such stresses or strains are typically concentrated locally by structural discontinuities, geometric notches, surface irregularities or damage, defects, or metallurgical nonhomogeneities. Fatigue may occur in three sequential stages: the formation of a crack, called "initiation"; the stable incremental enlargement of the crack in service, called "propagation"; and rapid unstable fracture, i.e., failure. Fatigue arises as a result of accumulated cycles of applied stress in service. The term "cycles" implies a repetitive loading condition or a randomly fluctuating load. Fatigue is not caused by a steady load or a one-time loading event. The phases of initiation, propagation, and final failure, though sequential, are distinct and governed by separate considerations.

Fatigue Initiation

Initiation of fatigue occurs at microstructure-scale nucleation sites within the material such as inclusions, pores, or soft grained regions, or as they become generated through microvoid coalescence by the straining process.*[1]* The presence of macro-scale stress concentrators, or more accurately strain concentrating features, enhances this process. Examples of stress concentrators are:

- grooves or notches
- threads
- abrupt transitions in metal thickness
- weld bead toes

- welding workmanship flaws
- manufacturing flaws in the pipe seam or pipe body
- pipe deformations such as dents or buckles
- mechanical damage such as gouges
- sites of environmental attack such as corrosion pits or stress-corrosion cracks.

Stress concentrators generically are characterized by a notch or notch-like geometry. A sharp notch will be more prone to form a fatigue crack than a blunt notch when subjected to the same cyclical loading conditions, because the sharper notch produces a more severe concentration of strain locally at its root. While it is true that fatigue can occur eventually if stress cycles are sufficiently numerous and large in magnitude, even where the material surface is free of gross stress-concentrating features, so many cycles of stress would be required for fatigue to initiate in the absence of a stress-concentrating feature that this is not a scenario of concern in a gas pipeline context, as will be demonstrated subsequently in this report. Conversely, the onset of fatigue is promoted by the presence of stress-concentrating features in proportion to their severity. This has important implications for pipe affected by mechanical damage.

The fatigue-crack-initiation behavior of a material is described by an "S-N" curve, which is a graph of the magnitude of cyclical stress amplitude, *S* (amplitude being half the total range of stress cycle or variation), plotted against the number of cycles, *N*, in which the cyclic stress amplitude will cause a failure. Some S-N data for plain carbon steel and low-alloy steel are shown in Figure 1(a).*[2]* The S-N curves are empirically derived from large numbers of tests in which polished round bars of material are cyclically loaded at specific nominal stress levels until fracture occurs. The data in Figure 1(a) were used as the basis for the fatigue design S-N curve in the ASME Boiler and Pressure Vessel Code (BPVC), Section VIII, Division 2, Appendix 5 shown in Figure 1(b). The curve is drawn well below the data points to provide a factor of safety. S-N curves for specific materials or structural weldment configurations can be found in other design standards and fitness-for-purpose standards as well.

The S-N curve demonstrates that larger cycles of stress result in failure in fewer cycle occurrences, while smaller cycles of stress result in failure after a greater number of cycles. At the left end of the curve, the stress amplitudes may greatly exceed the yield strength of the material, because what is shown as "stress" is actually a computed pseudo-elastic stress quantity

based on local strain that could fall well into the plastic range locally. The stress includes the concentrating effect of any notch. Large amounts of plasticity hasten the fatigue initiation process, resulting in failure in fewer cycles. This region of fatigue performance is sometimes referred to as "low-cycle fatigue" because it pertains to failure in a relatively low number of load cycles. At the right end of the curve, on the order of 10^5 or more cycles of stress are tolerable, if the magnitude of stress cycles is very low. This region of fatigue performance is sometimes referred to as "high-cycle fatigue" because it pertains to failure in a large number of load cycles. If stress amplitude is sufficiently low, the S-N curve flattens out and the fatigue life is infinite for practical purposes. This stress level is referred to as the "endurance limit". As-finished pipe and welds may not exhibit an endurance limit.*[15]*

The S-N curves are developed from tests to failure, so the number of cycles includes the propagation and final fracture phases of fatigue without explicitly describing them. It is presumed that in the absence of an initial crack, these phases comprise a very small proportion of the overall fatigue life.

The fatigue-initiation characteristics of a given material, design feature geometry, surface finish characteristics, and loading level are of great importance to the design of rotating machinery, vehicles, aircraft, and highway bridges because such structures rapidly accumulate millions of individual stress cycles. In contrast, the initiation phase of fatigue is of little concern with the pressure design of pipe, because the magnitude of hoop stress cycles due to pressure variation is in the range where 10^5 to 10^6 pressure cycles from 0-MAOP-0 would be required to cause failure, and this is far more than most pipelines would be expected to experience. The initiation phase of fatigue is a significant consideration in the design of piping systems that are free to flex in response to changes in operating temperature, such as piping systems located in refineries, power plants, or other process facilities. Here, the problem is not that stress cycles due to changes in operating temperature are particularly numerous, but rather that they are large in magnitude. The magnitude of flexural stress cycles in piping components, such as elbows and tees, are magnified by their geometries such that the range of stress cycle may be much greater than the yield strength of the material. Appropriate design for such circumstances is achieved by performing a piping "flexibility analysis" in accordance with the design rules for above-ground piping systems contained in standards such as the ASME B31 Code for Pressure Piping.

The resistance to fatigue crack initiation is generally proportional to ultimate tensile strength properties. However, the range of ultimate tensile strengths in line pipe does not vary over a sufficiently large range for this to be a significant factor. Resistance to fatigue initiation is enhanced by improvements in surface finish quality (smoother being better) and by treatments that impart compressive residual surface stresses (e.g., peening) or hardened surface microstructures (e.g., induction case hardening). Such treatments may be important to rotating machinery because they are initiation-sensitive owing to their high-cycle loading environment, but are not generally of value with pipe.

It is often assumed by equipment designers that the effects of fatigue are cumulative, in accordance with Miner's Rule of Linear Cumulative Damage. This rule of thumb states that the sum of fatigue-life fractions of various stress ranges, perhaps associated with different loadings or modes of operation, can be summed. Failure would be expected when the life fraction sum equals a value of 1. (Note that Miner's Rule cannot be assumed to apply when performing the explicit fatigue propagation analysis discussed in the following section, because incremental crack growth is not necessarily linear.)

Fatigue Propagation

The initiation process described above causes the formation of a crack in otherwise sound, uncracked metal. As load cycles accumulate, initiation is followed by propagation or enlargement of the crack in service. Fatigue failures frequently exhibit prominent concentric features on the exposed fracture surfaces, such as what is shown in Figure 2. These marks, referred to as "beach marks", indicate the incremental enlargement of the crack with continued cycles of loading in service. These fracture features are often somewhat elliptical in profile and typically are seen to emanate from the initial flaw, notch, area of local damage, or other stress concentration.

Propagation necessarily concerns a crack that is already present, so it is most useful to consider propagation in terms of parameters related to fracture mechanics. The crack-tip stress-intensity is an expression of the theoretical stress at the tip of a crack, derived from linear elastic fracture mechanics as $K = f\,[\text{geometry}] \times \sigma \times (\pi a)^{1/2}$, where σ is a nominal applied stress, a is the crack size, and K is expressed in U.S. Customary units of ksi-(in)$^{1/2}$ or in metric units of

MPa(mm)$^{1/2}$. The geometry factor accounts for the crack's configuration and its orientation in the plate. The geometry factor may change as the flaw enlarges.

The idealized configuration of a surface-breaking crack having a semi-elliptical shape, Figure 3, is the principal one of interest in dealing with seam susceptibility issues in line pipe, since the concern is for features having configurations similar to this. Various expressions for the crack-tip stress intensity at the tip of a semi-elliptical surface flaw in a plate have been developed, with some variations or alternatives. *[3,4]*

The stresses in service fluctuate over a range, $\Delta\sigma$, so the fluctuation in stress-intensity is $\Delta K = f\,[\text{geometry}] \times \Delta\sigma \times (\pi a)^{1/2}$. An operating pressure spectrum for a natural gas pipeline may look something like what is shown in Figure 4. Typically the largest cyclical component is seasonal, which means it occurs once per year. (Some pressure signals appear to go toward zero, implying a large pressure cycle. Most likely these are the result of instruments being taken off line for calibration or other events, rather than actual pressure swings.) The pressure signal is "stochastic", meaning it consists of an apparently random mix of signal amplitudes. In order to usefully account for the variations in stress, the operating history must be decomposed in terms of the number of cycles of various magnitudes. This is normally accomplished by performing a "rainflow" cycle-counting algorithm.*[5]* (The term"rainflow" is used because the analysis captures the effects of larger cycles widely separated in time, somewhat analogously to how a multilevel roof sheds rain to a wider lower-level roofline.)

Propagation or growth of a fatigue crack in service is governed by the "Paris Law", given as $da/dN = C\,[\Delta K]^n$ where da/dN is the increment of crack extension per load cycle, ΔK is the magnitude of the range of alternating crack-tip stress intensity associated with a given load cycle acting on the crack of size a, and C and n are material properties. The size of the crack, a, thus increases incrementally by Δa with each load cycle ΔN while the magnitude of the stress-intensity range, ΔK, increases with each increment of crack growth. The form of the Paris Law results in an exponential increase in crack growth rate and an acceleration of crack size as load cycles accumulate, as illustrated by Figure 5.*[3]* The practical implication of this is that a small crack may remain small for a long time, and by the time it is detectable, either by means of in-service examination (e.g., crack detection ILI) or proof load testing (e.g., hydrostatic pressure test), the remaining safe service life could be very short. The effect of a larger initial flaw is to

move the curve to the left, resulting in failure in fewer cycles. This suggests that achieving the largest possible margin between the test pressure and the operating pressure is of value to maximizing the retest interval where pressure testing is used as the method of assessment.

The value of *C* can vary by several orders of magnitude, while *n* has been observed to vary from 2 to 4, though for most pipeline materials *n* usually seems to fall between 2.5 and 3. A higher *C* and lower *n* will result in a faster initial crack growth rate that does not accelerate as greatly toward failure compared to a lower *C* and higher *n*, which results in very flat initial crack growth rate and more rapid acceleration toward final failure. If only an initial and a final flaw size are known, there is no one combination of *C* and *n* that uniquely defines the crack growth curve between initial and final flaw sizes for any given operating spectrum. "Typical" values reported for *C* and *n* in plain carbon steel are $C = 3.6 \times 10^{-10}$ and $n = 3.0$ for ΔK expressed in units of $ksi(in)^{1/2}$, though any given steel might exhibit very different values for the crack growth rate parameters. This "typical" relationship between da/dN and ΔK is shown in Figure 6.*[6]* Some fitness-for-purpose standards (e.g., API 579) also recommend higher *C* values specifically for welds in order to account for residual stresses.

The values of *C* and *n* are influenced somewhat by load cycle frequency and stress ratio (*R*, the ratio of minimum to maximum stress in a cycle), and may be influenced strongly by the chemistry environment that the crack tip becomes exposed to (e.g., dry versus aqueous, or the presence of oxygen, chlorides, sulfur, or hydrogen).*[6]* The exposure of the fracture to environments at the soil interface, under coatings, or in the pipe interior could enhance crack growth rates compared to those indicated by the "typical" coefficients.

"Retardation" (of the crack growth) occurs where an infrequent overload cycle blunts the crack tip and introduces a large plastic zone ahead of the crack. When the proof load is released, the residual stress field in the plastic zone is compressive, causing a delay in subsequent crack growth. Theoretically, beneficial retardation effects might be expected to occur in conjunction with high hydrostatic proof test pressures. While retardation is a proven phenomenon, it may not occur to a significant degree where the proof test is not greatly above the normal operating stress. (It does appear to play a role in delaying continued extension of near-neutral-pH SCC if the pressure test exceeds 100% of SMYS.) The effect of retardation is usually disregarded when

performing incremental fatigue crack growth computations for pipelines because assuming that it may have been operative when it actually may not have would be unconservative.

Accurate crack-growth life prediction methods do not exist in closed form. It should be apparent from the foregoing discussion that performing fatigue crack-growth life predictions is a highly technical process that requires specialized knowledge and some computational capabilities. It is not the sort of analysis that many pipeline operators are in a position to readily perform on a routine basis.

Final Fracture

The final stage of fatigue crack growth occurs when the crack-growth rate accelerates under the influence of ductile tearing and the crack grows to such size that it could fail at the next applied load cycle. The critical flaw size depends on the nominal stress, the material strength, and the fracture toughness. The crack configuration most relevant to the concern for pressure-cycle-induced fatigue is a longitudinal defect in pressurized pipe, for which accepted models exist.*[7]*

PRESSURE CYCLE FATIGUE IN PIPELINE LONGITUDINAL SEAMS

Susceptible Longitudinal Seams

Although it will be demonstrated subsequently that fatigue in longitudinal seams would not be expected to be an issue in any gas pipeline, it is worth reviewing which types of longitudinal seams have demonstrated susceptibility to fatigue, at least in a few liquid pipelines, as this appears to be a basis for the so-called "material threat" contained in Paragraph 192.917(e). The reader should keep in mind that fatigue crack growth in longitudinal seams as a result of pressure cycles has been experienced only in a subset of liquid products pipelines in which the pipe was affected by certain species of seam defect conditions, and the lines operated with relatively intensive pressure cycles. It would be quite incorrect to project this susceptibility to all liquid pipelines, or to all pipelines having a particular form of longitudinal seam.

<u>ERW Type Seams</u>

Autogoneous weld seams (e.g., electric resistance-welded and electric flash-welded

bends where there is no history of problems and no evidence of unusual external loadings being present. Probably only those bends residing in a pipeline segment that has exhibited problems with similar bends on prior occasions or that is located in a high consequence area would warrant excavation and inspection.

Dents and Mechanical Damage

The term "dent" describes a permanent deformation of a pipe's circular cross-section caused by external forces. The curvature of the pipe wall within the dent may be reduced, flattened, or reversed. A dent that has no scrapes, gouges, or other stress-concentrating features present in conjunction with it is referred to as a "plain dent". Dents caused by the installation of a pipeline on rocks in the ditch are usually plain in nature; dents caused by excavating equipment or other machinery striking a pipeline typically are not plain.

A dent that is prevented by the soil from pushing out (rerounding) under the influence of internal pressure is a "constrained dent". Rock-induced dents are typically constrained (unless the pipeline is excavated). A dent that is free to push out under the influence of internal pressure is unconstrained. Dents caused by excavating equipment typically are unconstrained. They reround as the indenting equipment is withdrawn from the pipe surface. Once a dent is excavated so that it can be examined, it is unconstrained regardless of whether it was constrained or unconstrained prior to excavation.

The term "mechanical damage" refers to features such as gouges, scrapes, or crushed metal introduced by contact from excavating or other mechanical equipment. Mechanical damage typically exhibits one or more of the following features:

- visible scrape, gouge, or smeared metal;
- localized metal loss or reduced wall thickness not due to corrosion;
- cracking within a scrape or gouge; and
- creasing of the pipe wall, or a long narrow indentation.

The features listed above occurring in conjunction with pipe indentations are referred to by 49 CFR 192 as "stress concentrating features". In most occurrences of mechanical damage, the pipe undergoes indentation simultaneously with gouging of the metal surface. The indentation pushes out ("rerounds") under the influence of internal pipe pressure as the damaging object withdraws

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HOW MANY EXCAVATIONS ARE REQUIRED TO CONFIRM THE ABSENCE OF SCC ON A PIPELINE?

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ABSTRACT

NACE Standard Practice SP0204, Stress Corrosion Cracking Direct Assessment Methodology (SCCDA), is used by pipeline operators to infer the presence or absence of stress corrosion cracking (SCC) on a pipeline. Results from direct examinations of the pipeline are easy to interpret when SCC is found. It is more complicated when SCC is not found. How many digs are required to confirm that a pipeline has a low probability of SCC? This paper examines the relationship between SCC threat modeling and the number of digs required to conclude that a pipeline is SCC free. Results show that when a reliable inspection prioritization model is used, few digs are required to infer that a pipe has a low probability of SCC. On the other hand, when the SCC model used to select dig locations does not take into account the relevant factor leading to SCC and their interactions, the number of direct inspection required can be high. Consequently the cost of the SCCDA process is directly linked to the quality of the SCC model used to choose direct inspection locations.

Key words: Bayes theorem, Excavation, SCC, SCCDA, Stress Corrosion Cracking

QUANTIFICATION OF THE DECREASE IN SCC PROBABLITY PER EXCAVATION

Equation 2 was solved for multiple values of *X* (*i.e.* probability of SCC being found given that SCC is present somewhere on the pipe resulting from the efficiency of direct examination in finding SCC). Results are plotted for the first 10 excavations in Figure 2. Results show that the decrease of SCC probability is not a linear function of the number of digs performed.

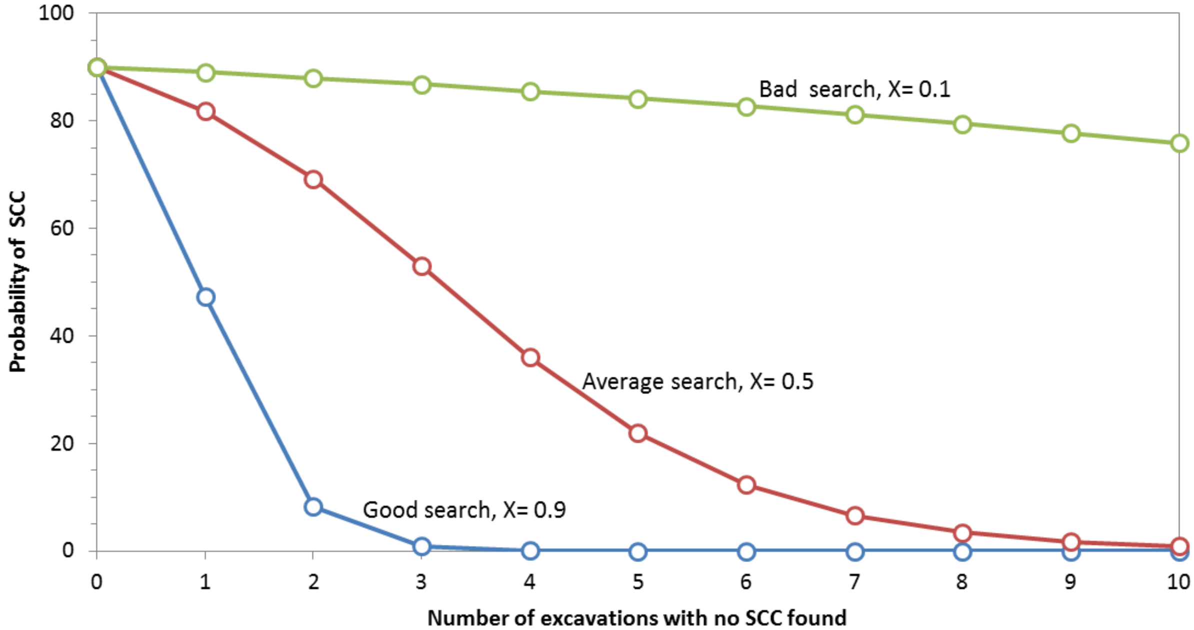

Figure 2: Drop in SCC probability if SCC is not found for the first 10 excavations for three values of *X* or $P(SCC\ found\ |\ SCC)$

According to Figure 2, if *X* = 0.9 only 3 excavations will be required to drop the probability of SCC from 90% to 1%. If *X* = 0.5 then 10 excavations will be required to drop the probability of SCC from 90% to 1%. And if *X* = 0.1 then 65 excavations will be required to drop the probability of SCC from 90% to 1%.

It should be noted that it is not possible to determine *X* (*i.e.* the efficiency of the direct examination in finding SCC) before the excavation site location selection method is tested in the field and SCC has been found. Therefore, it is important to determine *X* after the SCCDA is finished in order to improve the DA process over time (excavation site selection, crack detection tools). This is recommended in the NACE Standard Practice SP0204-2008 in the post assessment step. However, it is possible to qualitatively determine the value of *X* simply based on the type of algorithms used for excavation site selection.

Low *X* (<*0.2*): There is a low probability of finding SCC when SCC is present. Low *X* values should be expected when SCC digs sites are randomly selected or selected without the use of a SCC model. In such case *X* will be very low, typically in the range of the pipeline's SCC exposure, often below 0.1 (or 10%).
Average *X* (0.2 to 0.5): When SCC is investigated at sites selected during the ECDA process the likelihood of finding SCC may increase from random chance since ECDA looks for coating defects.

U.S. DEPARTMENT OF TRANSPORTATION

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PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

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GAS PIPELINE ADVISORY COMMITTEE (GPAC) TECHNICAL PIPELINE SAFETY STANDARDS COMMITTEE

+ + + + +

WEDNESDAY
JANUARY 11, 2017

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The GPAC met at the Hilton Arlington, 950 North Stafford Street, Arlington Virginia, at 8:30 a.m., Paula Gant, Chair, presiding.

MEMBERS PRESENT:

PAULA A. GANT (Government), Chair, Principal Deputy, Assistant Secretary, Office of International Affairs, U.S. Department of Energy
STEPHEN E. ALLEN (Government), Director, Pipeline Safety Division, Indiana Utility Regulatory Commission
MARK BROWNSTEIN (Public), Associate Vice President & Chief Counsel, U.S. Climate & Energy Program, Environmental Defense Fund
CHERYL F. CAMPBELL (Industry), Vice President, Gas Engineering and Operations, Xcel Energy Incorporated
J. ANDREW DRAKE (Industry), Vice President Operations and EHS, Spectra Energy Transmission, LLC

CHAIR GANT: Let's try to forge through and give staff some time to work tonight. I think that will increase our effectiveness tomorrow.

Okay. I'm going to suggest that we next take up the matter of internal corrosion control as relates to gas constituent monitoring. And I would ask the question for the chair's edification of how this is meant to be different from the gas quality specifications required by FERC in the tariffs that transmission operators have with their suppliers so that I could -- so that would help me guide this discussion more.

Could PHMSA staff help me understand that?

MR. NANNEY: We don't know where you are.

CHAIR GANT: 192.478. This is on internal corrosion, onshore transmission monitoring and mitigation. So this is the monitoring and mitigation program to identify potentially corrosive constituents. That's the

next one in my list. Did I -- it's on the next page after interference currents.

PARTICIPANT: I'm not sure I know where you're -- could you repeat the question, please?

PARTICIPANT: Yes, we're not sure what --

CHAIR GANT: Okay. So this is 192.478, internal corrosion control on short transmission monitoring and mitigation. This is the requirement to develop and implement a monitoring and mitigation program to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects.

MR. NANNEY: Okay. This is on the internal -- what's the question on it now that I know what section?

CHAIR GANT: Okay. Sorry about that. Sorry. My question is, so I can help guide us through the next bit of the discussion, how is this intended to be different from the existing

FERC requirements to have gas quality specifications established between the pipeline and shippers?

MR. NANNEY: Well, I'm not sure I've looked at the FERC requirements. I don't know -- I've looked at them in the past, but that's been many years ago.

So just to tell you, I mean, what this is set up for is for there to be a monitoring and mitigation to make sure if you got corrosive gas coming into your system to monitor it. If you look at 478(a), it's got here for onshore transmission pipelines each operator must develop and implement a monitoring and mitigation program to identify potential corrosive constituents in the gas being transported and mitigate the corrosive effects.

And then potentially corrosive constituents should include but now are limited to carbon dioxide, hydrogen sulfide, sulfur, microbes, free water either by itself or in combination. And each operator shall evaluate

the partial pressure of each corrosive constituent by itself or in combination to evaluate the effect so the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures.

So it's basically to set it up if you have a corrosive gas. So I don't know of the FERC -- offhand if it's -- it's probably set up for 16 parts per million on H2S. It could be eight parts per million and then based -- but I haven't -- like I said, I haven't looked at it to answer your question. Some of the gas company reps may know, but I haven't, like I said, looked lately.

CHAIR GANT: Okay. Thanks, Steve. What I'm trying to understand is there have been several comments that this particular aspect of the regulation duplicates either other PHMSA regulations or other regulatory requirements.

MR. NANNEY: Oh, that duplicates it?

CHAIR GANT: Right. So that's one of the things I'm trying to understand starting with

shippers on these pipelines. Off-takers have requirements for the quality of gas they receive.

MR. NANNEY: Okay.

CHAIR GANT: And that's part of these -- pipeline operators also maintain -- I mean, part of maintaining the integrity of the system is to not have a gross of materials in your system. So I'm trying to back into what's causing the concern that these requirements duplicate other requirements so we can pull that apart.

MR. NANNEY: I haven't -- I missed the comment. I haven't looked at the comment. If I have, I've forgotten it. And so I'm not sure who the comment's coming from and what they're referencing. So I hear you, but we'll have to look at it. But I just don't know it right now.

CHAIR GANT: Steve?

MEMBER ALLEN: Steve Allen, IURC. Wouldn't this deal with integrity management? I mean, from the standpoint that if you have corrosive material entering into your system,

it's a threat you have to deal with anyway. So perhaps that's the duplicate nature we're talking about here.

Secondly, it seems to me that this is kind of a -- I don't want to say a ready, fire, aim approach, but it seems to me that -- and I think I read somewhere that perhaps this standard should -- or this rule should apply only to those pipelines that have some history of internal corrosion because of corrosive material. There's an awful lot of pipelines out there that don't have internal corrosion as well.

So anyway, to answer originally, I think the duplicate nature is probably related to some of the integrity management threat analysis for this one.

CHAIR GANT: Cheryl?

MEMBER CAMPBELL: Thank you. Just a couple of things, and I think one of what's driving this issue of looking -- I mean, obviously if you're operating a steel system, you should be analyzing the threat of corrosion under

your integrity program.

I think what a lot of the LDC operators struggle with is there is sort of a natural -- well, I shouldn't say short of -- sort of. There is, right? I mean, there are tariff requirements for the interstate pipeline system with limits to the constituents that you're talking about. And that might be what you're trying to get at, Paula, is a lot of that stuff is taken care of well upstream. And a lot of the LDC operators struggle with saying, all right, why do we need to monitor it again?

For what's worth, I mean, we have interconnects. We also connect to some processing plants and we do watch the lines that are downstream of processing plants more carefully because of exactly the reasons that you're talking about, Steve.

I say again though is this an issue of training and making sure that we are inspecting fully and asking operators how they're evaluating the threat of corrosion and are they fully

evaluating that threat?

The other thing I guess I'd like to ask PHMSA to do before we meet again is to bring the data and the statistics on what has been caused by internal and external corrosion. I heard what Sara said, but the data that I just got sent was there's been about two a year over a 20-year time period.

So I think some data to say how serious of a threat is this, how big of an issue is it, where we might need to add some additional specificity to the code, because operators aren't responding. I would absolutely agree with that. If that's really what's going out there, we -- and we need to poke and prod and get people moving, but let's clarify the data and understand the magnitude of the problem. I, too -- the last one of any significance that I recall is Carlsbad. And certainly a horrific accident, but I'm struggling with any additional ones with IC.

So I think that's why people are saying it's duplicative is there's things that

already say we should be evaluating the threat, we should be doing something about it when we find it. And you're probably going to hear me say this a lot as we go through this -- Alan, I think you've heard it from me one on one before, too -- are we sure we're asking the right questions and pushing the operators, right, and when we're doing the inspections? Writing another rule isn't going to solve that problem because people are still -- if they're not going to do it, they're not going to do it.

CHAIR GANT: Thanks, Cheryl.

Andy, Chad and then Sara, please?

MEMBER DRAKE: I think the issue that really is causing a lot of concern is the must, the word "must," that operators must use gas stream quality monitoring at all points, inlet points on the pipeline. And it talks about shall do these things. And I think that's where it becomes -- it doesn't solve the problem. And I think Cheryl is -- what she's saying is resonating with me is getting people to monitor

these things is just going to be more stuff to do. It isn't going to solve the problem.

We can go -- dry gas systems. We can put monitors all over it. They're dry gas systems. It isn't helping. Just interesting. What we're trying to do is get folks to be more deliberate about the risk of internal corrosion and actively confirming your status against it, not trying to manage all of the incoming variables that could be driving it. That isn't going to be informative.

If you are not in a dry gas system, you should be considering things to do to make sure you don't have this problem actively. And I think maybe switching the language off of "musts" to "shoulds," adding some conditions to qualify -- I think what we're trying to do is help give guidance to operators about what is the screening tools to define where you should be looking and what you should be doing to make sure you don't have this problem, not just looking for variables. Get more on toes, not on your heels.

And I think that provides more clarity that's useful to people. And that would be my recommendation is come off of this must, provide some qualification language about conditions where you're worried and then list tools that they can use to confirm the integrity of the system, not just tracking more and more data. That's just -- that's a distraction in my opinion.

MEMBER ZAMARIN: Chad Zamarin, Cheniere Energy. I think we should probably follow up on the data. I like Sara's comment around the incident statistics because I think it helps frame the issue. I wonder if maybe that included offshore incidents where internal corrosion has been more of an issue. And this requirement is focused on onshore gas transmission, so I do think we should make sure we're talking about the right data and putting it in the right context, because I do think our experience is that this has been an issue that has not been as significant.

And following San Bruno, which was 17 years ago, 16 years ago, we've done a lot of work on internal -- I'm sorry, Carlsbad. Following Carlsbad; that was 16 years ago, we've done a tremendous amount of work on internal corrosion monitoring and mitigation.

I echo Andy's comments. I think one thing about gas monitoring that you have to be careful of: One, input does not define the aggregated product within our pipelines. We have this issue all the time where we look at not necessarily just for internal corrosion issues, but we look at single data points, and they're not representative of the kind of commingled gas stream. So you have to be careful that that is not a panacea for identifying whether or not you have a potentially corrosive environment.

So like Andy, I like the idea of saying you should be monitoring and monitoring should consider or may include, but having this must requirement I think is what's raising the concern. Thank you.

CHAIR GANT: Thanks, Chad.

Sara?

MEMBER GOSMAN: So just to follow up on the data, yes, I'd love to see the breakdown on that, because again it was very surprising to me, that number.

I'm looking at this section -- and by the way, thank you for going section by section, because it's -- I think it's very much focused the discussion and gotten past generalities.

I think that this section actually gives a lot of discretion to the operator to create this program, this monitoring and mitigation program. You certainly do have to create it and you do have to use monitoring equipment, but once you do that, the question of how you mitigate is left up to the operator evaluating coupons or other suitable means -- I'm just pulling this language from the proposed rule.

I think a lot of this actually -- I recognize that the word "must is in here, but I

think "must" can and should be used in regulations. The question is is how much flexibility do you have if you have say this other great technology? It seems to me that that is built in at least partly here. And if there are places where it isn't and we need to, I think that would be a great thing to do. But as a concept having this type of program to essentially, right, try to move forward on corrosion seems to me a very good policy idea.

CHAIR GANT: Sue?

MEMBER FLECK: Hi. Could you pull this section up? I don't have a copy of the code with me, so I'm getting a little confused. Thanks.

CHAIR GANT: Cheryl, did you have a comment now or do you want to wait?

MEMBER CAMPBELL: I actually did want to follow up on -- I think there are ways to monitor for internal corrosion in a way other than the monitoring equipment that is specified. I mean, I agree with you that we should be paying attention and we should be watching for it, but

installing monitoring equipment at inlet points is not the only way to do that. And I think that's the point.

And I think that my gas transmission friends who mostly have done ILI on their entire systems would say they know where they've got those problems and where they don't. And I feel like I do as well without installing that monitoring equipment that I then have to maintain and take care of.

So the point being, right, I mean, there are different ways to do it and are you actually engaged in monitoring and watching for this threat on your system? And if you find it, then doing something about it.

And, Alan, I got to believe that's really what you want the operators to do is -- are you really monitoring it? Use a method that works, right, that you can defend. And then when you do find it, do something about it. I think that's your point.

CHAIR GANT: So to summarize, to play

back before PHMSA staff responds on what I'm hearing as the chair, that there is an agreement that you want to be on top of internal corrosion and that there are a number of ways to get information that allows you to understand where internal corrosion may be occurring in your system, that focusing on a particular data point or set of data around gas quality may generate a lot of data that doesn't necessarily give you the most useful or full range of useful information.

Second; and this is why I asked my question about the gas quality specifications, is there was a great deal of work done by the industry in the years following Carlsbad and a very open process to examine this matter of gas quality. And my observation has been that parties involved in moving gas and purchasing gas to move, transmission service, have reflected the learnings from that process in the tariffs that you've negotiated over the years. So there's a great deal of information that's been integrated into the commercial arrangements in this sector

based on the understanding of gas quality and what it does to these physical systems.

So I think that's an important triangulation to get at what are we trying to solve for here? We're trying to make sure, I think, that we understand where internal corrosion is happening in the system first. And that's the emphasis here, as Sara's noted. This doesn't even really address the mitigation aspects of it in this particular section. How do you best stay on top of where it's happening?

Alan?

MR. MAYBERRY: Well, a couple points. First, Cheryl, I would agree. I mean, we need to ask the right questions and we need to clarify the expectations. And that helps both us as the regulator and the operator.

And I agree with the point that -- I think next time we can come back with some data and talk -- further talk about this one here and see where we need to go on it.

It is a risk that's out there. It's

an area that we have seen a history with. Not a significant history like some other areas, but it's an area that we -- at least in doing this we thought we would identify -- add a little more prescription to the expectation of do you really know what you're getting? You have a contract that limits hydrogen sulfide or CO2, but you always get that. Or do you know that -- I know during upset conditions you probably don't get that, that those are rare for it, hopefully. But anyway, that's -- pass it on to -- that's all I had for now, yes.

CHAIR GANT: Sara, is your card still up? Okay. Sorry.

MEMBER GOSMAN: Sometimes I leave it up.

Well, yes, just to respond, I mean, I think if there's a better way of handling it, of identifying it than what's in this particular rule, that should be built into the rule. I just don't want to get rid of this entire section because of that particular issue. I think it can

be drafted in such a way that we still get at the issues.

I guess I'd make sort of a systems point, which is that throughout this conversation I'm hearing but we can do this better, right? Just let us do it better. And it strikes me that I don't know that much about the special permit or whether there's another process like that out there, but I think particularly when you get into prescriptive requirements everybody feels better if you have a system where you can go in and say I have this equivalent way of doing it. Let me prove to you.

And you put the burden on the operator in that system because that's the way it goes, right, at that point. But the operator who has that burden shows you that there's a better way of creating this kind of monitoring and management plan. You approve it. And I think that's a fair tradeoff to again more prescriptive requirements that may not allow for the latest and greatest.

CHAIR GANT: Thanks, Sara.

Those cards popped up while I wasn't looking. Ms. Fleck?

MEMBER FLECK: Snuck up on you. Sue Fleck, National Grid.

I guess the only issue I have with this -- I'm not a -- I'm really not a corrosion expert, but I'm paranoid enough to worry about how the regulators might deal with it, my state inspectors. The word "potential" is a little bit scary, because they could just turn around and say we have a potential for it everywhere, so install the equipment everywhere.

So, because they don't like to make -- the state inspectors don't like to make judgments, so it's easier for them to have a -- well, just do it everywhere and then I'm safe. I'm covered. I never have to make that kind of -- and I'm not trying to be disrespectful or anything, but it's going to open us up to having to install the monitoring equipment at every single take-on point. So just through that out

there. "Potential" is a scary word.

CHAIR GANT: Cheryl?

MEMBER CAMPBELL: Just -- you made a comment earlier, Paula, about the commercial arrangements with the tariffs, and we -- I am convinced, right, as gas and electric come together, we're going to see yet another national conversation on gas quality, and in fact have asked ourselves internally within our company if it's time to start that conversation. Because the turbines, right, once you get them tuned, right -- I mean, there's all kinds of issues. And we have quite a few generators behind our system, and so we're dealing with that today.

But I think that's only going to spread, and it's going to spread upstream to the transmission lines as well. At some point we are going to have to have tighter controls on the quality to make all that stuff work the way that it needs to work in the -- on the path that we're all on.

So I think you're going to see this

sort of convergence, right? Now that doesn't mean that as an operator we shouldn't be prudent and responsible and be monitoring and mitigating where we should, but I do think that the commercial side of this is going to continue to drive this conversation perhaps even faster than what we're doing.

So that's just a statement. I mean, I don't think it changes what we need to be doing here, but I do think we're going to keep seeing that change.

CHAIR GANT: Steve?

MR. NANNEY: Just one thing for the Committee to consider. Gas is bought and sold and paid for based upon the composition of it. And I would be very surprised at where the ownership of this gas is being measured and being transferred and being paid for. What we're requesting here to be looked at monitored is not being done today at any of these places where it's being changed, because that's how you get paid for your gas.

I would also be -- if you've got in your tariff of any amount, I would not -- I would be very surprised if H2S, CO2, all the issues for corrosive gas are not being monitored, because that also has to do with how much you pay on the cash register.

So I would recommend that the industry folks go back and check with their measurement and be sure that -- I'm hearing that we're asking for too much, but I'm not sure if we're not asking for what you're probably already getting and looking at anyway.

CHAIR GANT: So, Steve, I think some of that applies in the intro to this section, that there are different ways by which the companies understand what's going through their system. I think what becomes a bit more problematic is how detailed the specifications are on how they will know what's in their system and the methods by which that -- this would not sync up with the way it is currently, that they are aware what's in their systems.

So that may be something for future discussion between --

(Simultaneous speaking.)

MR. NANNEY: That's what I'm asking is come back and tell us how you're getting what you're getting. It would be good to know that.

CHAIR GANT: Sue?

MEMBER FLECK: Yes, I can give you one example. In some of our transfer points we -- the equipment is owned by the supplier and we go and we witness the test while they do it. And we look at the constituents and we see what they're doing. So we would be out of compliance with this because we don't have our own monitoring equipment that we're looking at, that we're taking care of.

But we do get the information and we validate it in other ways. Or take an occasional sample, send it to the lab and have it tested. I mean, there's lots of ways we can do it without having monitoring equipment running around the clock at every input station. So just a couple

of examples.

CHAIR GANT: Alan?

MR. MAYBERRY: I think that got brought up earlier though is you may not have online monitoring at every station. I mean, do you measure H2S at every gauge station? Probably not. Do you?

(No audible response.)

MR. MAYBERRY: So, but it's something -- you have a contract that says you'll limit it to this amount, you know, CO2, water. But, and you're -- maybe you have a program. I think we're talking about a program to monitor for that that may involve online and it may involve periodic checks depending on your level of risk for that.

CHAIR GANT: Okay. So I think that PHMSA staff has received some interesting observations on this to continue to digest. It sounds like there is some room for understanding -- mutual understanding about what information that operators already have about gas quality.

But also the second point of -- is a focus on gas quality appropriate for informing your understanding of internal corrosion?

So we'll leave that to rest with PHMSA staff and get onto the next fun part of this.

So I think that it might be time for us to take the hill on external corrosion control, protective coating. Is everyone up for this? That means we might not make 3:30. Is there one that you think we could make 3:30 with?

(Simultaneous speaking.)

CHAIR GANT: I think we need to have a discussion about the protective coating and the requirement around DCVG.

(Simultaneous speaking.)

CHAIR GANT: Yes, this is 461(f), right?

(Simultaneous speaking.)

CHAIR GANT: Okay. You have the numbers better than I do.

MR. McLAREN: Yes, I think 319 is where it starts, isn't it?

BEFORE THE
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
WASHINGTON, D.C.

Pipeline Safety: Meeting of Gas Pipeline Safety Advisory Committee	Docket No. PHMSA-2016-0136

COMMENTS ON PHMSA'S GAS PIPELINE ADVISORY COMMITTEE (GPAC) MEETING HELD JANUARY 11 – 12, 2017

FILED BY
AMERICAN GAS ASSOCIATION
AMERICAN PETROLEUM INSTITUTE
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

April 5, 2017

H. Operator Case Study: Internal Corrosion Gas Monitoring Equipment

During the first GPAC meeting, the discussion concerning the current state of gas stream monitoring throughout the national infrastructure as well as the costs to comply with PHMSA's proposed requirements was a point of confusion and concern. The Associations provide the following information to guide future conversations.

<u>The Proposed Requirement</u>

PHMSA proposes to introduce a new requirement within Subpart I for monitoring and mitigating internal corrosion. The proposed requirement prescribes that operators of onshore gas transmission pipelines "develop and implement a monitoring and mitigation program" for internal corrosion. The program must include monitoring at points where *potentially* corrosive contaminants enter the pipeline. PHMSA's use of the term "potentially" is a concern for operators. While today PHMSA may have a loose interpretation of "potentially", individual inspectors, state regulators, or PHMSA may have vastly different interpretations in the future. One such interpretation is that *all* receipt points on a gas transmission system could be *potential* points where corrosive constituents could enter.

In the next section of these comments the Associations offer suggested edits to PHMSA's proposed requirements that mirror the discussion during the GPAC meeting and the concerns identified through these comments.

<u>What are operators currently doing to address the threat of internal corrosion?</u>

Operators currently install filters, separators, dehydrators and drips in their system to remove free liquid and corrosive constituents from their pipeline systems. Additionally, where necessary, operators are installing corrosion probes or taking corrosion coupon samples to verify the absence of internal corrosion in their system. Finally, operators are currently adhering to the existing requirements in §192.477: *Internal corrosion control: monitoring,* that requires operators to determine the effectiveness of internal corrosion mitigation strategies. In April 2007, PHMSA also added new subsection §192.143 and expanded §192.476 to address design and construction standards for managing internal corrosion.

Where Integrity Assessments (ILI, DA, Pressure Tests) have not identified internal corrosion, and pipe inspection reports have not indicated internal corrosion, any prescriptive requirement to install gas monitoring equipment would be an unnecessary diversion of resources from addressing a company's more significant risks.

<u>What does it cost to comply with PHMSA's requirements?</u>

In the proposed requirements of §192.478(b) operators must monitor for "potentially corrosive constituents [that] include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and free water, either by itself or in combination." The Associations believe that in order to meet this requirement, operators may have to install a Gas Chromatograph, a H2O Analyzer, an O2 Analyzer and a H2S Analyzer. Additionally, for operational requirements, safety and security reasons, this equipment is typically housed in a small shed-like equipment building. PHMSA's statements in the PRIA support the Associations' view, particularly the comment that "the proposed rule would require the use of specific gas quality monitoring equipment for HCA segments, including but not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and hydrogen sulfide sampling."[19]

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[19] PRIA. Page 88.

The table below outlines two transmission operators' estimates for the capital investment cost of this equipment. There will be additional costs associated with the operations and maintenance of the equipment. These costs greatly exceed PHMSA's estimation of $10,000 per location for monitoring equipment costs used in the PRIA.[20] PHMSA estimates that there are 40 receipt points throughout the nation's gas transmission infrastructure that will require the installation of new monitoring equipment. The Association believes it is likely that there are tens of thousands of these points. If PHMSA moves forward with the requirement as proposed, the potential industry-wide cost of this requirement is several billion dollars.

Gas Chromatograph	$85,000
H2O Analyzer	$55,000
O2 Analyzer	$35,000
H2S Analyzer	$75,000
Auxiliary Equipment & Equipment Building	$110,000
Total Equipment Costs per Receipt Point	**$360,000**

Operator Case Studies: Impact of the Proposed Internal Corrosion Gas Quality Monitoring Requirements

Operator Case Study 1
LDC Operator
30 Supply Receipt Points from Local Production & Transmission Pipelines

Supply Source	Current Practice	Additional NPRM Requirements
Local Production	LDC takes a gas sample monthly and monitors for hydrocarbons, CO2, H2S, H2O and BTU content.	Design, construct, and operate gas chromatographs and constituent monitoring at each receipt point.
Interstate Transmission Pipelines	Gas tariff requires the Interstate Transmission Pipeline Company to supply pipeline quality gas. The LDC monitors the supplier's "Gas Quality" postings, which primarily includes the BTU and CO2 content and most do not include H2S and H2O content. **	Design, construct, and operate gas chromatographs and constituent monitoring at each receipt point.
	Current Internal Corrosion Monitoring Costs: $400/ sample on Local Production receipt points	**Total Compliance Cost:** Approximately $10,800,000 + annual operations & maintenance costs

[20] PRIA. Page 91. Table 3-75. It should be noted that the requirement for §192.478 is not limited to gas transmission pipelines in HCA segments, but instead applies to all gas transmission pipelines.

Operator Case Study 2
Gas Transmission Pipeline Operator
290 Supply Receipt Points from Transmission Pipelines & Storage Facilities

Supply Source	Current Practice	Additional NPRM Requirements
Interstate Transmission Pipelines	The following equipment is installed at a subset of the 273 receipt locations: Gas Chromatographs 192 H2O Analyzers 120 O2 Analyzers 105 H2S Analyzers 11 Equipment Buildings 101	Expand the installation of gas chromatographs and constituent monitoring to all receipt points. Gas Chromatographs 81 H2O Analyzers 153 O2 Analyzers 168 H2S Analyzers 262 Equipment Buildings 172
Storage Facilities	The transmission pipeline company has H2S Analyzers installed at 4 of the 17 storage facilities.	Install H2S Analyzers at the remaining 13 storage facilities.
	Current Internal Corrosion Monitoring Costs: Annual Operations & Maintenance Costs on Existing Equipment	**Total Compliance Cost:** Approximately $61,645,000 + annual operations & maintenance costs

I. Redline Code: Suggested Changes to Proposed §192.478

It is the Associations' position that PHMSA's existing regulations provide more than appropriate internal corrosion protection for all transmission pipelines. These regulations prohibit the transportation of corrosive gas unless investigated and addressed before transport (§192.475(a)) and require all operators to investigate and minimize internal corrosion whenever found (§192.475(b)). In addition, existing rules require consideration and avoidance of internal corrosion risks during construction and design of gas pipelines, and during replacements or repairs (§192.476). Pipeline operators have an obvious interest in maintaining the quality of the product transported through their systems. Therefore, the addition of §192.478(b) for all transmission pipelines is unnecessary. At a minimum, the requirements in proposed §192.478 should only apply to non-dry gas systems where liquid water is present.

The corrosion incident data clearly shows that internal corrosion is not a significant cause of serious onshore pipeline incidents, further suggesting that existing rules and industry action are sufficient. If PHMSA believes that additional internal corrosion control requirements are necessary, the Associations suggest the following based on the GPAC discussion, as well as concerns shared by the public or identified through written comments on the Proposed Rule.

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

(a) For non-dry gas onshore transmission pipelines, each operator must develop and implement a monitoring and mitigation program to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects, as necessary. Potentially corrosive constituents include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and ~~free~~ liquid water, either by itself or in combination. Each operator must evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe, as necessary, and implement mitigation measures.

(b) ~~The monitoring and mitigation program in paragraph (a) of this section must include:~~

~~(1) At points where gas with potentially corrosive contaminants enters the pipeline, the use of gas-quality monitoring equipment to determine the gas stream constituents;~~

~~(2) Product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents;~~

~~(3) Evaluation twice each calendar year, at intervals not to exceed 7-½ months, of gas stream and liquid quality samples and implementation of adjustments and mitigative measures to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.~~

(c) ~~If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked at least twice each calendar year, at intervals not exceeding 7 ½.~~

Operators should evaluate each system transporting non-dry gas, including results of the monitoring program, to determine appropriate mitigation measures. The same mitigations are neither necessary nor appropriate for all situations.

NACE SP-0106 references "liquid water" instead of "free water."

The Associations believe that PHMSA's proposed §192.478(c) is unnecessary as it is exactly duplicative of existing §192.477. PHMSA and the GPAC should determine where this requirement is managed moving forward.

DEPARTMENT OF TRANSPORTATION
OFFICE OF PIPELINE SAFETY

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PIPELINE AND HAZARDOUS MATERIALS
SAFETY ADMINISTRATION

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GAS PIPELINE ADVISORY COMMITTEE

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TUESDAY,
JUNE 6, 2017

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The Gas Pipeline Advisory Committee met in the Westin Arlington Gateway, F. Scott Fitzgerald Room C, 801 North Glebe Road, Arlington, Virginia, at 8:30 a.m., The Honorable David W. Danner, Chairman, presiding.

MEMBERS PRESENT:

DAVID W. DANNER (Government), Chairman, Washington Utilities and Transportation Commission
STEPHEN E. ALLEN (Government), Director, Pipeline Safety Division, Indiana Utility Regulatory Commission
CHERYL F. CAMPBELL (Industry), Senior Vice President, Gas Engineering and Operations, Xcel Energy Incorporated
J. ANDREW DRAKE (Industry), Vice President Asset Integrity and Technical Services, Enbridge Gas Transmission and Midstream
SUSAN L. FLECK (Industry), Vice President, Gas Pipeline Safety & Compliance, National Grid

MS. WHETSEL: That was just a little kindness to --

(Off microphone comments.)

MR. HILL: That was a yippee, not a yea.

MS. WHETSEL: That was a yippee, not a yea, yes. Okay, Robert Hill.

MR. HILL: Yea.

MS. WHETSEL: And Bob Kipp and Rich Pevarski are not here. So it's unanimously passed.

MR. DANNER: Okay, and the motion passes. It is now 11:56. You want to push through for one more or is this a good time to break for lunch?

(Laughter.)

It appears that this is a good time to break for lunch. So we're in recess until 1:30.

(Whereupon, the above-entitled matter went off the record at 11:56 a.m. and resumed at 1:32 p.m.)

MR. DANNER: We are back on the record.

Steve, do you want to tee up the next item?

MR. NANNEY: The next item we're going to is internal corrosion, 192.478, and again the issue there is the current requirements are not always effective for preventing internal corrosion. The basis is lessons learned from previous incidents. PHMSA's proposing to require a program for monitoring gas streams to identify corrosive constituents and a mitigation program and a periodic program review.

Some of the committee comments from the last meeting is that it should only be required for lines carrying corrosive gas, that some distribution operators rely upon the transmission suppliers to monitor the gas quality, they don't do it themselves and they may not own gas monitoring equipment. Monitoring frequency of twice per year is too frequent, and they need to harmonize 192.477 with duplicates the proposed 478(c).

What does PHMSA suggest, based upon what we heard at the meeting at the committee?

The first item is we heard and are considering is, provide flexibility for our operators to determine the internal corrosion monitoring program by adding, as necessary and where applicable, in paragraph (a), as suggested in the industry letter docketed April 5th.

The next item was addressed comments on methodology, and that some distribution operators rely on suppliers for gas monitoring equipment, modifying (b)(1) as follows:

At point where gas with potentially corrosive contaminants enters the pipeline, the use of gas quality monitoring methods to determine the gas stream constituents.

Number three, address frequency of monitoring by changing the frequency from twice per year to once per year, and then lastly on this slide is delete the proposed paragraph (c) and refer to 477 and 478(a).

MR. DANNER: Okay. Let's go to public comments. Are there any public comments on this item?

MR. CLYDE: I'm Peter Clyde with Louisville Gas & Electric. We operate 400 miles of gas transmission pipelines and roughly 45 miles of high-consequence area. I wanted to point to 192.478, paragraph d(1). As proposed, it talks about at points where gas with potential corrosive contaminants enter the pipeline, that we have to do the gas quality monitoring. Steve just mentioned that he was going to modify paragraph (a) and add "as necessary and where applicable."

I just want to make sure that that addresses the situation in gas storage fields. We operate five gas storage fields. One of those fields has over 80 wells in it, and as the rule is written today, it appears that gas monitoring equipment would be mandated to be installed on every single wellhead, and don't feel that that was the intent or was factored into the cost benefit analysis. So I want clarification that the proposed changes of paragraph (a) address that adequately and that will not be required.

Thank you.

MR. DANNER: All right. Thank you. Are there any other public comments?

MR. NOLAN: My name's Mark Nolan with Xcel Energy. I work with Cheryl and we're members of the American Gas Association. We operate 2400 miles of transmission lines, about 220 are ACAs. I'd like to maybe reinforce some of these comments. We, in Colorado alone we have 88 entry points or supply points into our system and most of those, 65 or so, are from upstream interstate transmission providers and we also have those situations where in some cases they are providing quality measurements, some cases where we're providing that measurement. We also have storage fields with many wells that we don't believe need individual monitoring.

This is something that we, in 2016 we did a lot of in-line inspection, we roughly had 300 or so where we excavated our pipeline. Two of those were related to callouts for internal corrosion. Those happened to be on, not active

corrosion but pipelines that had previously received gas from storage fields.

It doesn't really look like the internal corrosion threat is commensurate with this type of rule-making as originally proposed, so we're happy to see the modifications and get the clarifications in, as we commented.

MS. KURILLA: Hi, this Erin Kurilla with the American Gas Association. Just like some of my members just said, we thank PHMSA for taking a look at the comment -- industry consensus comments that were submitted in April. It's very apparent to us that the voices were heard.

Just a point of clarification. In the first bullet, the "where applicable and as necessary" makes perfect sense for this regulation. However, in the proposed (b), the sentence that proposed, it states that "the monitoring and mitigation in paragraph (a) must include" and then itemizes out three elements that these internal corrosion programs must

include. We just think having that prescriptive actions associated with "where applicable and as necessary" is a bit confusing in regulatory text. We just want to make sure that (b) takes a look at the words "must include."

MR. FORET: My name is Francis Foret with Targa Resources in Houston. I understand that we're going to address gathering at later meetings, but to make a point here on clarification, if those parts of gathering become jurisdictional that are contemplated, the number of monitoring points in our gathering systems are going to be in the thousands, not the hundreds. That's just something to consider from a cost standpoint.

MS. FARRELL: My name is Lynda Farrell, High Plains Safety Coalition out of Pennsylvania, member of the USEITI Multi-Stakeholder Group. I wanted to ask about the terminology of "internal corrosion monitoring as necessary and where applicable." Seems to be very loose terminology, in light of -- and I'm

going to quote this, because I just recently read this: the 2017 API and AOPI Annual Liquids Pipeline Report affirmed that the liquid pipeline incidents have increased over the past five years.

And John Stoody, the Vice President for Government and Public Relations, said: there's not a single overarching explanation for the shift, however, he noted issues of welding and corrosion.

So I'm wondering, given that industry data, why the language is really very loose and nebulous.

MR. DANNER: Right. Other comments?

MR. MORTON: This is John Morton, Enterprise Products. Another point of clarification that the rule needs is, it references undefined terms such as micro, sulfur, free water, and vague new requirements to calculate the partial pressures, and you really don't provide any guidance on what all that means.

MR. DANNER: Okay, any more comments from behind me? Then I'll turn to the committee. Is there anybody who wants to begin the discussion on this item? No discussion on this item. Oh, I'm sorry, Andy.

MR. DRAKE: This is Andy Drake with Enbridge. Thank you. Just to clarify the comment that was made a few minutes ago about the liquids industries having an increase in corrosion rates, that is the liquids industry. I think the gas industry would show that internal corrosion rates are actually declining, and if it helps we can provide a submittal to the docket that would show that trend. I think it's just data. I'm not contesting what you're reading, because I think it's exactly right, I'm just trying to put it in context.

MS. FARRELL: It was liquids, but PHMSA's own data actually indicates that the 20-year trend is either flat or rising.

MR. DRAKE: If we want, we could make that submittal to the docket. It would at least

help to fresh up the data.

MS. FARRELL: Thank you.

MR. DANNER: Okay. You say you have other data. Would you like to share that in the doc as well? It's in the doc. All right.

MS. GOSMAN: Sara Gosman. A couple points on the suggested changes. I'm looking through the "as necessary and where applicable" and trying to see how they modify the various clauses in this. I think it would be helpful for the folks in the industry groups who have suggested this language to give a background about what they're trying to do with this language, because to me it can be read broadly.

For example, the first "as necessary." It could modify the fact that you have development and implementation of the monitoring and mitigation program altogether. It seems to me that's a lot of discretion to give an operator and quite different from what the proposed rule was.

MR. DANNER: All right, you are invited

to comment on this language. Cheryl?

MS. CAMPBELL: Cheryl Campbell, Xcel Energies. I'm sorry, sir, I speak in stories, so I offer up an example. I am going to refer back to some comments that Chad made earlier about, you know, corrosion is a real threat to transmission pipeline systems, and operators should have a good corrosion management program and our states should hold us accountable for those corrosion management plans.

As Mark stated earlier, we have quite a few inlet points to our system. Many of them are from interstate pipelines who do an excellent job of monitoring the quality of that gas. We just don't see a lot of internal corrosion, hardly any at all as a matter of fact.

However, we also have some points, and we would argue that any monitoring to those points doesn't make sense and does not help pipeline safety. It adds cost, but it doesn't help safety. We also have a number of points that come into our system from a local basin that is

known to be wet. Those plants occasionally have upsets and issues. Those are point we monitor much more closely and carefully, and we do tend to have equipment on those points to monitor the quality of the gas that comes in.

The Integrity Management Program should be taken as a whole, right, and we should be making sure that we have that solid corrosion management plan. So when I read this, and I hear what you're saying, that it feels ambiguous, but what I would expect is that I recognize that I have a difference in some of those inlet points and I'm taking action to differentiate them and my state regulators should be asking me those questions and ensuring that they're comfortable with the actions that I've taken to manage the corrosion. I see Steve is going to, and I welcome your comments, Mr. Regulator.

MR. DANNER: Is there anybody else, so that we can avoid having Steve? Okay.

MR. ALLEN: Steve Allen, Utility Regulatory Commission. "As necessary and where

applicable," I think "as necessary," to me, and Cheryl you mentioned you have points of entry onto your system from an interstate transmission operator that has all the instrumentation and the testing in place to know what the quality of the gas is and what sort of constituents are on board. So if you have an operator that's suppling gas to your system like that, I'd say adding something is not necessary.

But like you said, if you have native gas or perhaps gathering lines, underground storage where, you don't know what you don't know unless you actually monitor it. What the right time frame is, I don't know, but to me, "where applicable" is where you simply don't know. If you know you're okay, then you're all right.

So I guess I agree with what you're saying, and we actually have a situation back home right now where we have some native gas, and we're struggling to try to find a regulation to hang our hat on. It comes back to, in our case it comes back to the operator that would be

accepting the gas and they're perfectly within their rights to say no, we don't want it because we don't want to monitor it and we don't know what's in it.

I think that this is a good balance. Perhaps there needs to be some more definition around necessary and applicable, I don't know. Bur in my own mind's eye, I'm good with it.

MR. DANNER: Chad, is your card up?

MR. ZAMARIN: Maybe you see a little more context. I mean, we have a lot of pipeline mileage and the internal corrosion is, we try to take a fairly surgical approach to identifying where that threat exists. It is not something like external corrosion where the environment exists across the entire pipeline system. I think we're just trying to recognize that "where applicable" means, you know, the majority of our pipelines are dry gas systems, there are tariffs that prevent certain quantities of constituents that could be internally corrosive from getting into the systems but there are unique parts of

our system that do have this particular threat.

But the key is to make sure we're not implementing something across all pipe, we're not treating all pipe as equally susceptible to this threat, because it's not. This is one of those, in fact if you read the integrity management processes that we developed going back almost 20 years, internal corrosion was one where getting to, actually doing something, requires you to go through a series of filtering analyses that help you identify what pipelines would be susceptible to the threat.

So the intent of "where applicable and as necessary" was to try to recognize that. This isn't a threat that does exist across all pipelines, and if we put those resources and these activities across all pipelines we spending a lot of useless calories. We need to focus our energy. We need to focus on where the threat actually exists.

MR. DANNER: Can I follow up with a question on that? What kind of record keeping do

you do when you're saying, okay, it's not applicable here, it's not necessary here, or it is applicable there, it is necessary there. Would there be a way to audit that a decision was actually made?

MR. ZAMARIN: Sure. Our interior management process requires us to assess for all the specific threats to pipeline integrity. I think there are nine under ASME B31.8S and internal corrosion is one of those threats. You have a risk management process where you're required to assess your system for the potential for internal corrosion, where you can identify through data regarding the gas composition, where you can identify other variables around the pipeline that the threat does not exist, you focus your energy on those other threats that exist in that particular area.

So we have to document that analysis, and we have to do it formally on an ongoing basis. PHMSA comes in and audits that process. We have internal corrosion as one of those threats

that we're continually monitoring for on pipelines that typically receive tariff-quality gas. It's a relatively light activity set on pipelines that receive wet gas or gas out of storage, areas where we could find areas -- Our risk assessment also looks for low spots in the pipeline, we look for dead-legs where gas flow may not sweep anything that gets into the pipeline through, so when we go through our risk assessment, we have to identify those area.

Those are the areas where we focus our internal corrosion monitoring activities first. If we find activity in those area, we may have to broaden our analysis but it's truly an iterative process. It is codified in our risk management process. The code requires us to consider internal corrosion on all of our segments, and we have to document that analysis.

MR. DANNER: Thank you. Any other comments? Steve Nanney?

MR. NANNEY: I'd just like give a little food for thought on this. My experience

shows that operators, especially the transmission operators, they're getting gas into their system, they are measuring the quality of that gas. They're either paying or getting paid based upon the quality of that gas, so they are monitoring it. So what's up here is taking that into account, that you've got a monitoring system. A prudent operator is not going to be taking H2S or CO2 above a certain level into their system because it is going to create a problem.

What this proposed rulemaking and these comments are saying, ensure you're getting that data. If your operations folks aren't getting but your cash register folks, your accountants are, make sure you're getting that question. But I'd say the operational folks are the ones that are getting it for them so they have it.

So this is just saying take prudence, get that information and use it, is what I see this as conveying to the operators and to PHMSA. But let me say I would be very surprised if

there's gas coming in cold from others to these major transmission companies if they're not measuring the whole gambit from water seal, CO2 and H2S, and also the make-up of the gas because that's what that's what they are getting paid is based upon.

MR. DANNER: All right, thank you. Sara Gosman?

MS. GOSMAN: Thank you, everyone, for helping to understand the background on it. I guess I just read this language differently because it seems to me that to require a "development and implementation of a monitoring and mitigation program to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects." By its nature you create a program but you're going to focus on the areas where that potentially corrosive effect is going to exist.

To me it adds another level of uncertainty or discretion to a broad-scale management process that's being requested. And I

guess the other thing that I think about these particular set of changes, is collective what they're doing is giving a lot more discretion on whether to do this kind of development and implementation, and what we're left with is really a lot of discretion on the front end about the program, one requirement for monitoring methods, no requirements on evaluation or on the actual mitigation, and pushing out from a year to two years the review process. Collectively, to me, that really guts a lot of specifics of this particular policy.

MR. DANNER: So you would simply take out the terms "as necessary and where applicable."

MR. ALLEN: Steve Allen, IURC. I read this to be really directed more to those operators that have transmissions, not the large transmission operators, they're the smaller transmission operators that might not be operating within an HCA and wouldn't necessarily have some of the integrity management procedures

in place or controls in place.

I kind of go back to what you were asking about, Sara. There are other regulations out there that would lead an operator to address this from a risk-modeling perspective. The example that I brought up, where we have some native gas there in the state. If an operator chose to go ahead and accept that gas into his system without knowing what was in it, I don't have a regulation to hang my hat on. Okay? I think most operators would not accept that level of risk, but I've got nothing to hand my hat on to say no, you can't do that. So I think that there are other regulations out there that probably address your concerns.

This verbiage, especially the "as necessary and where applicable" kind of helps me in that I can hang my hat on it with the smaller operators and say look, you know, if you're going to accept that, you have to be monitoring. You have to know what's in it.

MR. DANNER: Other comments? I'm not

sure where that left it. Sara Gosman, did Steve's comments resolve your concerns or are your concerns still out there?

MS. GOSMAN: Yes, they're helpful. I see the need for an additional set of requirements that can help you clean up in the areas where you don't currently have authority. I guess, again, when I read this language, what I worry about if even those folks, the folks that you're worried about could use this "where necessary and if applicable" to push back against regulation.

And I don't know how you enforce that. I'm still struggling with this idea of how are you going to document necessary and applicable, in a way that you can come as a state regulator and say to them, look, we think this is what you should be doing?

MR. DANNER: Steve, I kind of heard it as, this is belts and suspenders with the other processes. And yet again the question is, what do we have that's enforceable?

MR. ALLEN: Well, if this were codified, my expectation is that the audit protocols would also go along with it. This would something else that we would be auditing, too, to make sure that operators are following this. I don't know if that helps or not. It would be something that we would inspect against and hold operators accountable for.

MR. DANNER: And so you believe that with this language you could say, that's not appropriate or that is necessary?

MR. ALLEN: I like the way it is, with the applicable and where necessary and applicable. That helps me. And it also prevents requiring operators to do more work than they need to do. Most of the gas that enters Indiana is tariff gas, and there's all sorts of controls on that. It's the underground storage and the gathering lines and the native gas that enters the system that I'm more concerned about.

MR. DANNER: Okay. Andy Drake?

MR. DRAKE: Yeah, I think that, to

respond a little bit to Sara's question, I think a lot of the discussion of the last meeting, that I can remember anyway, was around the open nature of the original language. It could have been read, or would have likely been read, to apply to all meter stations, all the interconnects to all pipes everywhere.

That was a lot of the conversation that came in and I think, Steve, the language that went to the front of this wording, this proposal, was, or non-dry gas environments. Which was intended to take a lot of the meter stations out, particularly those that are downstream of all this processing, as we come to city gates and other places, Union connects with other pipes downstream of gathering areas.

That's a lot of the gas metering stations, and to be sampling gas there for corrosion constituents and internal corrosion is not helpful. And then as we read the proposal, I think that Steve has referenced it, we can't see all the language, it was really the as

necessaries and where applicable, as I was reading them, was in the context of a non-dry gas environment, you will look at these constituents as those constituents are applicable and where necessary, so it was talking not about that the evaluation is discretionary, it was that the details of the analysis was discretionary.

That's how this reads, and I can't see that up here, so I'll have to defer to Steve as to how does that fit in context?

MR. DANNER: Thank you. Steve, can you, actually I have paragraph (a) in front of me. Can you tell me where the language "as applicable and where necessary," where that would actually go in the sentence?

MR. NANNEY: That's why I raise this. What we did, where it says to refer, at the bottom of the bullet, refer to 477, the 477 in the current code is internal corrosion control monitoring.

It starts out, "If corrosive gas is being transported," that's the key. We're not

using non-dry gas, we were using "If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year with intervals not exceeding seven and a half months."

So we were tying it in, just like what Andy says, whether you use corrosive or non-dry, it's similar terms.

MR. DANNER: I'm still, as I'm looking at 478 (a), where in the sentence they're inserted? I wasn't here at the last meeting. I don't have a context.

MR. NANNEY: Of where 477 would be?

MR. DANNER: No, where you're adding the language in paragraph (a) where it says, "as necessary." Where in the sentence are you putting "as necessary?"

MR. NANNEY: It would be in there where it says, the first sentence, it would be where it

says, "and mitigate the corrosive effects as necessary," at the tail end of the sentence. And then in the next sentence it would be, "potentially corrosive constituents include but are not limited to carbon dioxide, hydrogen sulfide, sulfur, microbes and liquid water" was added there, and then the where applicable, "Each operator must evaluate the partial pressure of each corrosive constituent, where applicable by itself or in combination."

MR. DANNER: Okay. Thank you.

MS. GOSMAN: Sorry, there's an additional "as necessary" at the end there

MR. NANNEY: "On the internal corrosion of the pipe, as necessary and implement mitigation measures."

MR. DANNER: Thank you.

MR. NANNEY: That's at the bottom of (a), if you look where that would be inserted, after 'monitoring.'

MS. GOSMAN: Let me make a suggestion, Terrence. Can you put up that language on a slide

so we can see it?

MR. DANNER: There it is. You still have your card up. Are you ready for --

MS. GOSMAN: Thank you for putting this up. I think, again, that the discussion that is being looked for here, it's unclear to me just in terms of the clauses, where these "necessary and applicable" are being put in, exactly what we're trying to get discretion for. Is it the monitoring, is it the fact that we have a program at all, is it the evaluation and particular mitigation approaches, all of those things I think would help me. Because for example, the first one you put "as necessary" at the end, and I'm just unsure what that's modifying.

MS. CAMPBELL: I'm not a lawyer, and Alan, I'd direct this at you, but I think the "as necessary" is intended to say where you have corrosive constituents, not whether or not you should have a program. Or have I misunderstood, because I think that's, our point is that happy to do it, right, where I believe I have issues

and I have identified I have internal corrosion possibilities, doesn't make sense where I have tariff gas that I already know is well monitored and I do not have that thread.

So to your point, Sara, if the "as necessary" isn't in the right place, then, Alan, I think that's what PHMSA was looking for, is where you have this threat. Am I right or wrong?

MR. MAYBERRY: Exactly. Here I am, and I've said this before, the latest challenge is developing a national policy that's applicable everywhere and not to be so dogmatic that we write something that may apply to everything and it would be unnecessary, but to apply where it's needed.

Here again, and I think Steve, you alluded to this as well, this won't, for myself as a regulator, it still won't impact what I do to see that this was addressed where it was needed. If it's not, we definitely will be talking, but I think that's put the onus on the operator to make sure they're addressing it where

applicable, but it's not making me put a policy out there that says, address it everywhere and even in places where it's not necessarily needed to do.

MR. DANNER: Okay. Andy Drake?

MR. DRAKE: I think for clarification, what was the intent of asking CJ what was the intent of the trades when they wrote this on the behalf of so many other operators, but I think the big issue that was trying to be accomplished was clarifying the non-dry gas applicability of this requirement, and if you'll notice, it's not there but we, I don't know what the "in addition to requirements of Section 477" means, that's back to the corrosive gas part.

I think that's the biggest issue that people are having. Without that qualifier at the front, it applies to all meter stations, all gas interconnections, which is not what the intent was. It needed that filter. If we get that filter into place, and I think the as necessaries and the where applicables and other things are not

really that significant. It's really the front-end filter that is the big deal, and I defer to the rest of my industry cohorts here.

MR. DANNER: Would you be able to address that, by saying that for on-shore transmission pipelines, each operator must develop and implement a monitoring program to identify those pipelines where potentially corrosive constituents in the gas are likely to be transported, and then mitigate those corrosive effects.

MR. DRAKE: I think all we would probably add to that is just in front of onshore transmission would be non-dry gas onshore transmission. You put that in there, it separates it. And that's all we're trying to do. If the rest of this is bothering people, I think we can remove that. It's not the intent. It was just to get that differentiation in the front.

MR. DANNER: Any comments on that submission?

MS. FLECK: Sue Fleck, National Grid.

Why not at the beginning of paragraph (a), use the same qualifier you use in 477, and you get right there, so you just say: if corrosive gas is being transported, and then let this go. So there's no confusion and you don't have to go back and read 477, you say it again right here, you cover it and then I think we'd all be in a little happier place. Sue Fleck, National Grid.

MR. ALLEN: Steve Allen, IURC. If corrosive gas is being transported, and that's the first part of 477, and I don't know if we could do this, but if corrosive gas were the potential, because you don't know. How do you know it's corrosive gas if you're not monitoring it? Other than the fact that you could have some tariff gas, okay, that's non-corrosive gas. That's fine. It's tariff gas. We know it's okay. But just by saying, if corrosive gas is being transported, well, that would suggest that you know it's corrosive.

So I'm saying, or if the potential for corrosive gas being transported, or something.

I'm not sure how to work that in there, but the idea is that we don't know if it's corrosive unless you test it or monitor it for, like I said, the gathering lines and native gas and so on.

MR. DANNER: All right. Any response to Steve's suggestion? All right, let the record reflect that Andy's shaking his head. I don't know if it's going up and down or sideways. Okay, he's fine with it. Sara?

MS. GOSMAN: I think we're on the right track. I feel like if all this discussion is moving towards this question of a category of lines that we can just move out of the picture and we can agree on that, I think that's a much better place to be in. How that language is drafted, I would agree that it's the potential. As I read this, it's about identifying potentially corrosive effects, right? Not -- If you knew it already I think you wouldn't need to identify the potentially corrosive effects. So finding a way to get in there, potential, as the

sort of initial evaluation stage, I think is important. But I like this direction, I guess I'd say.

MR. DANNER: So is it, could you say something along the lines of, if corrosive gas may be transported, and so if you have a pipe that's just taking tariff gas and it's not likely to have contaminants, then you could exclude that. Would that be tight enough?

MS. FLECK: Sue Fleck, National Grid. Then you might as well take the whole thing out, because one of your regulators could say, I need, anything could happen, you know. A meteor could hit the earth, who knows? When you put potential in there or maybe, you've opened it up to every single station again. I'm not comfortable with that.

MR. DANNER: Well, yes. I guess that's the way, literally that could be any pipeline that is capable of carrying corrosive gas, which would be everything. But I see the problem with this too, is the problem that if corrosive gas,

how do you know? Chad?

MR. ZAMARIN: Yeah, I agree with Sue that it causes some consternation, but I think that if the understanding is that by saying potentially corrosive gas is being transported, that it means that the operator has to define what constitutes a potentially corrosive gas, that we have to document that criteria.

I think that's how I read the intent of what that's saying, that we have to go through a process to identify what could constitute a potentially corrosive gas and if we've done that, then we've defined a filter, for lack of a better term, that focuses the rest of these requirements on our activities. I'm comfortable with that. I recognize the risk that it creates, but I also sense that we've got to figure out a way to create some form of filter without making it so that it's totally ambiguous.

MR. DANNER: Andy had a proposal earlier. He modified the sentence where it said, for onshore transmission pipelines. I think he

said, for non-dry gas, or, what was that phrase?

MR. DRAKE: Non-dry gas.

MR. DANNER: Okay.

MR. ZAMARIN: This is Chad Zamarin again. I think that's kind of another way of saying this is a way you determine whether or not you have potentially corrosive gas --

MR. DANNER: Well, it is very objective. It doesn't leave a lot of discretion, but is it too narrow?

MR. ZAMARIN: At the end of the day, the most important factor for preventing internal corrosion is keeping water out of the pipe. These constituents that are identified here don't pose a threat unless they're in the pipe with the addition of having water in the pipe.

You can have carbon dioxide in the pipe, it doesn't cause any problems but as soon as you have carbon dioxide in the pipe in the presence of water, it creates an acid and causes internal corrosion of the pipe. If you never have water in the pipe, you will never have internal

corrosion.

Hydrogen sulfide requires water in order to create sulfuric acid and so, the concept is, and what we do when we monitor gas coming into our pipeline, is we have a dew point requirement and we have alarms and if gas comes into our system that is water in the stream, then we shut it in or we have to take action. We just lost the language. Could we have the language back? Thanks. I guess they're telling us it's time to move on.

What, I'm just wondering if we took out that first clause, "if corrosive gas is being transported," if we took that out is the remainder of that paragraph acceptable to the committee members? Does anyone have an objection to what is left? Sara?

MS. GOSMAN: I don't have an objection, but just a clarification. I'm presuming from the technical side here, that we're saying that essentially dry-gas transmission pipelines are not going to have corrosive constituents in them,

thus no need for an identification or evaluation of potential corrosive constituents. Does that sort of say that technical fact, that is the case, am I right on that??

MR. DANNER: That's the way I would read it.

MS. GOSMAN: Okay. With that clarification, I think that's great. And then I would ask for removal of the "as necessary and where applicable."

MR. DRAKE: I would offer, the way I read the where applicables, this is important, actually: Each operator must evaluate the partial pressure of each corrosion constituent. If you take where applicable out, we have to evaluate the partial pressure of every single constituent, whether it's there or not, which isn't -- I think the intent was, where applicable, if those constituents are there, then you have to do that. If they're not there, you do the ones that are there.

That's the way I think it was intended

when it was put in there. It wasn't that the evaluation is discretionary. It's that you do it where the constituents are applied, where you realize those constituents.

MR. DANNER: Okay, but we've just limited now only to only non-dry gas onshore transmission pipelines. So we've got the program, the whole program is scoped here.

MR. DRAKE: But the constituents are up in front. CO2, hydrogen sulfide, sulfur, microbe liquid, that's the constituents. So you would just do those constituents that are present. Not every single one of them. If that wasn't in the gas stream, why would you be evaluating them? I think that's the way it was intended.

MR. DANNER: Chad and then Sara.

MS. GOSMAN: So you're saying the rule, as you read it, would just require operators to evaluate the partial pressure of every gross of constituent? Ever. Because --

MR. DRAKE: If you took the word applicable out, it would make you do that. If you

put it in, then you're just doing the partial pressures for the ones that are present.

MS. GOSMAN: Okay. So is there a way to start that, and I will just make an apology here because it's clearly me that's driving this in terms of wordsmithing, and I apologize for the wordsmithing piece of it, it's just that actually these particular words, my mentor when I was first in practice, called wiggle words, are particularly concerning to me in terms of rules.

This is why I'm focusing a little bit on this text here. Could we put a phrase at the beginning, or maybe rather than wordsmithing it to PHMSA, maybe just as a point, we can say, where those have been identified, right? Then there's the evaluation. I think just in terms of clarity in what this is doing.

MR. DANNER: So in other words, you could take out the word, where applicable, there and put in identified. If each corrosive constituent --

MS. GOSMAN: Yes.

MR. DANNER: Okay. Steve?

MR. ALLEN: Steve Allen, IURC. I'm almost there, but I still get back to at the very beginning where we said, for non-dry gas. As a state regulator, we go out and we are inspecting or auditing an operator, how will we know that they know that they have non-dry gas coming out of an underground storage or native gas? Is there another regulation out there somewhere that would require them to monitor that, or to measure that? I guess perhaps I'm looking for a qualifier here that says for non-dry gas onshore transmission pipelines, where the operator has a basis of knowing it's non-dry gas.

MR. DANNER: So what I heard earlier is that you had made an assumption, basically, if it's taking tariff gas --

MR. ALLEN: Okay, so that's their basis. That would be their basis for saying it's dry. But I'm saying, absent a basis like that, or something that they can rely on to say, hey, I know that this is dry gas. Without that, I still

have issues, because there's going to be gas input into a system that may be corrosive.

MR. DANNER: I would suggest that come out, but I don't recall going back why it was added in there, because it seems to be unneeded. And I think we have to come out of this creating some kind of presumption, because otherwise it goes back to the discretion of the operator.

MR. ZAMARIN: This is Chad Zamarin, Cheniere Energy. I know we said we weren't going to wordsmith, and we're wordsmithing, but I think conceptually it sounds like there's agreement on what we're trying to achieve, that we're trying to focus on those parts of our systems that have the potential for internal corrosion and we're trying to filter and focus the requirements to those areas that have been deemed as susceptible to that threat.

Maybe it's not the best use of our time, and I know words do matter and I know we've got to get it right, but I think we can at least get it on the record that we all agree that there

needs to be some lead-in that focuses this and maybe it just requires a little more time for PHMSA to work that, and that maybe in a room like this isn't the best place to do that. It feels like we have alignment, we're just struggling with words.

MR. DANNER: Yeah, I, well, this is speaking for myself now, I know what you're saying. This is one, though, where the precision of the words, I think, is so important that if we don't wordsmith here, we're going to endorse this paragraph, it's going to be wordsmithed differently than we think will be satisfactory. So I actually think that this might be one where we should take an extra five, three, fifteen minutes --

MR. ZAMARIN: I'm with you, hang in there, we're with you.

MR. DANNER: So, all right, I saw a card up. Sue?

MS. FLECK: Sue Fleck, National Grid. I'll take a shot at it. If you leave it as we

have it up there, with for non-dry gas, then it's incumbent upon the utility to be able to justify to their regulators how we determined it was not dry gas. So if we have tariffs, we have the gas constituent reports we get from the provider from a pipeline, we have all that information, we can show that back to the regulators and say, I don't have to look at this one.

If were getting from somewhere that we don't have any information, then we have to monitor it or check it or do something to validate, so I think this is okay because you can come to us and say, how did you make that decision and then you can determine whether you're comfortable with what we say. And for most of the time, we're going to be getting that information from whoever we purchase the gas from and if not, then we have to figure it out.

MR. DANNER: Steve?

MR. ALLEN: Steve Allen, IURC. Exactly. That is my concern. If we go in and say, oh, no, we have dry gas, okay, tell me more about that.

Well, we just have dry gas. How do you know that? We just know it. Well, tell me why. They have to have some basis.

MR. DANNER: But that, whether it's in the paragraph or not, they would have to have some basis. I mean, the regulator's going to say, how do you know that was a dry gas pipeline? And they're going to have to come back and say well, all the gas we purchased was off of a tariff.

MR. ALLEN: And that gets back to the wordsmithing component of it. If we could come up with, just string together a few words that basically say what Sue just said as a modifier, then I think we're there.

MR. DANNER: All right. Again, my own view is that this is going to be a question where the regulator's going to say, tell me why this is a non-dry gas pipeline. I mean, that's not a term, that's not a legal term. That's a term that's going to have to be defined based on the evidence that one is looking at, that the regulator is going to ask for. Would that be

sufficient? Anyone else? Andy?

MR. DRAKE: Just at the risk of thinking out loud, I think you could pick up some language here. Certainly the value here is that this record does create some, this transcript creates a record for compliance and interpretations. We're trying to give guidance to PHMSA. I think what we have heard is that things like, based on gas tariff standard, based on sampling reports, or based on reports from suppliers, the obligation to prove is on the burden of the operator, that decision. If those three sets of criterial help to do this, I think you could add them here. Or we can give that to PHMSA to consider in how they draft the final language and extricate ourselves a little bit from the wordsmithing. But I think we can give some guidance either in the rule-making directly, or in the record that is the basis behind the rule for enforcing it.

I think that's the intent everybody is saying here. I see people out in the audience

shaking their head yes too, so that's a good alignment. But if those words help, I think we could put those in there too.

MR. DANNER: Okay. So the problem is that we are leaving some ambiguity here? We can tell PHMSA, I think PHMSA has an idea from this what our intent is. It's really going to get down to whether they can draft something that reflects that intent, and around the table here we haven't able to do so so far with perfection, but we've, I think we're getting close. Cheryl, is your --

MS. CAMPBELL: I just offer up a potential, and I agree with Andy. I think everybody is in agreement on the intent of what we're trying to do here and we do want to narrow the universe from all meter stations, but a possibility: where the operator has a reasonable basis to determine that the gas being transported is non-dry.

So you basically put the onus on the operator to say, and I think that's what we've been trying to say. The operator has to say,

yeah, I have a dry gas, here's my lines or my inlet points that are dry, and here's my inlet points that are non-dry, and the non-dry ones are the ones that I need to be -- And then this stuff is all applicable, right?

MR. DANNER: Okay. So you're going back to a reasonable standard and --

MS. CAMPBELL: I'm not sure how else to do it.

MR. DANNER: Yes. And so the language would say: for onshore transmission pipelines for which the operator has a reasonable basis for --

MS. CAMPBELL: To determine the gas being transported is non-dry.

MR. DANNER: Okay.

MS. CAMPBELL: And then you, as the regulator, how did you come to that conclusion? There's a zillion questions around that that the state regulator could be querying, most of which I don't want to answer so I'm not trying to give you any ideas.

MR. DANNER: Rich?

MR. WORSINGER: Mr. Chairman, I just want to back up and make sure I understand, and if I understand then I'm hoping everybody else will understand. What's at issue is, or what's not at issue, we understand what to do if we have non-dry gas. We're all in agreement to that? And we know what to do if we have gas that is dry gas. What's at issue here is where we're just not sure whether it's dry or non-dry. Is that correct? And we want to make sure we're not treating all gas as if it is non-dry gas. So could we leave this up here and just maybe add something that just says, if the operator cannot confirm if it's dry or non-dry gas, then they have to further investigate and confirm.

MR. DANNER: Any response? That sounds reasonable to me. Alan?

MR. MAYBERRY: I think we're creating a little bit of an issue getting crossways with 477 that's referred to there. First it is, we changed it to non-dry in this excerpt here, but if you go to 477 it's corrosive. And now we've

changed it from corrosive to non-dry. It would really make it easier on us as we write this thing to be consistent in our terms. Otherwise we need to deal with 477. So I would prefer to do that, if you guys feel inclined, to change non-dry back to corrosive. Be consistent with 477, which is referenced there, and it just keeps us, you know, okay, we say corrosive here, we say non-dry here, it confuses everyone.

MR. DANNER: So you would change the non-dry gas to --

MR. MAYBERRY: Corrosive.

MR. DANNER: Corrosive onshore transmission pipelines?

MR. MAYBERRY: We can deal with exact terminology since we're not wordsmithing, right?

(Laughter.)

MR. DANNER: Words matter. All right. Is the group okay with that? Sara, your tent is up?

MS. GOSMAN: Just a question for you, Alan, I completely understand the need for

regulatory consistency here. As I read the rest of this paragraph, what I understand this to be about is identifying potential, right? So when you're think about that initial category of corrosive gas being transported, are you thinking that includes the broader range of gas that's being transported where we would want to see somebody actually evaluate the corrosive potential?

MR. MAYBERRY: We'll address that and any other questions that may come up, like it might be generally dry gas but you may have to consider for upset conditions and the like that might be better addressed, really it's difficult to address the whole universe here, but we'll have to give some further clarity and guidance in the material we put out there.

MS. GOSMAN: So at this point I'd suggest that we leave it with the agency. I think we're all close to the same place here.

MR. DANNER: I agree. So I guess, is there any further discussion on this language, or

shall we put a motion in front of us? Does anybody with a working mike want to make a motion? We're not quite ready? Okay, go ahead.

MR. ALLEN: In the second line where it says twice per year to once per year, I think that's where that once per calendar year, within 15 months should be added.

MR. WORSINGER: Within 15 months, not to exceed, yes.

MR. DANNER: Is everybody okay with that change? I see a couple of tents up. Sara, your tent's up.

MS. GOSMAN: So I don't want to push my luck here but I just have a question about (b) 2 and 3 and removing them. I assume the reason here is concern about the specificity of the particular technologies and mitigation approaches. Because I notice that it says, or other technologies, so it seems to open the door to, gives a list but then includes other technologies, so I would read that as being an open-ended response, but just giving some

examples of potential mitigation approaches.

MR. DANNER: Steve Nanney, do you have a response to Sara's comment?

MR. NANNEY: You said (b)2?

MS. GOSMAN: Yes, that's right.

MR. NANNEY: We were planning to keep (b)2 in. I did not see where we had said we'd keep (b)2 out.

MS. GOSMAN: Oh. My mistake. So you're keeping (b) 1, 2 and 3 in and just shifting the language in (b)1?

MR. NANNEY: But we were planning to take c) out, is what was recommended. (b)2, we were planning to first, they must include, we heard that comment on (b) the lead in, then (b)1, equipment, we were looking at becoming methods. (b)2 would stay as is, is what we were considering there, and then (b)3 we would make some changes based upon what we heard as far as the evaluation period and how the samples were done, which we referred back to 477.

MS. GOSMAN: Okay. Thank you for that

clarification. The lead-in on (b) is the same?

MR. NANNEY: Yes. So it would be, the monitoring and mitigation program in paragraph (a) of this section must include. And we had some comments on the "must include," and we would take a look at that to see if we could make any adjustments there. I'm not saying we can, but we could look at it.

MS. GOSMAN: Okay. I guess I would add my point of view, which is that I like the word must.

MR. DANNER: Okay. Is there, Sue?

MS. FLECK: Yes, this is Sue Fleck, National Grid. I thought (b) was struck. So going back to it, it could be misread as saying you have to do all of those things. The monitoring, whenever you say must include and then you put a list in, people are going to think you have to do every one of those things. So that (b)2 is problematic, with the lead-in that says, "the monitoring and mitigation program must include" all of those things. I thought you had struck

that.

MR. DANNER: So, Steve Nanney, you were saying is that it say should include?

MR. NANNEY: We haven't said we would change it to should, or we heard must in Sue's comments then and we heard it earlier, we will go back and look at it but we're not ready to say that we would change it to should.

MR. DANNER: So (b)2 does say, or other technology to mitigate. It doesn't say you need to consider every one of them, or implement every one. Okay. We have language in front of us and I'm looking for a volunteer to make a motion.

All right, I move that we approve the language that is up on the screen right now, which is voting language for closer control of internal corrosion, Section 192.478, the proposed rule as published in the Federal Register and the draft Regulatory Evaluation, with regard to the provisions for internal corrosion are technically feasible, reasonable and cost-effective and practical if the following changes are made.

1. Modify (b)1 as follows: at points were gas with potentially corrosive contaminants enters the pipeline, the use of gas-only monitoring methods to determine the gas stream constituents.

2. Change frequency of monitoring a program review from twice per year to once per calendar year, not to exceed 15 months.

3. Delete proposed paragraph c) and refer to 192.477 in 192.478(a), and,

4. Limit the applicability of paragraph (a) to the transportation of corrosive gas. PHMSA will provide additional guidance based on the GPAC discussion.

Is there a second?

MR. DRAKE: Second.

MR. DANNER: Okay, there is a second, by Mr. Drake. Any further discussion? Rich?

MR. WORSINGER: I'd like to recommend instead of saying must, we change that to may include at the beginning of (b)1. In general (b).

MR. DANNER: In general (b). So

monitoring may include --

MR. WORSINGER: Instead of must include.

MR. DANNER: So, any discussion on that suggestion? One of the things for me, again, speaking for myself, it's a little incongruous here is that you have in paragraph 3 some pretty prescriptive, evaluation twice each calendar year, at intervals of -- this is very prescriptive language, and you're saying, okay, you may do that, it sort of begs the question about why you would be so prescriptive if you don't have to do it.

MR. ZAMARIN: I just have a question. I wonder if, would it work for the group if it said must consider instead of must include, and then that requires the operator to go through that list and identify those things that are applicable. I think one of the concerns is, for example, in (b)2, it is a list of potential solutions but not all of them will be appropriate. Does must consider instead of must

include work?

MR. DANNER: In 2, though, it does say in other technology. I don't see that as an exhaustive list that must be implemented. To choose these or something else. Alan?

MR. MAYBERRY: Yes, Alan here, this might be an occasion to use where applicable or as necessary.

MR. ZAMARIN: One of the problems is, to give you an example, when you talk about (b)1, you talk about having gas monitoring at every inlet to the pipe, but then in another item you talk about corrosion coupon monitoring, if you have multiple inlets in a storage field, you're not going to put gas chromatographs on every flow line in a storage field. You're going to need to come up with a different way.

MR. MAYBERRY: I think we understand that. What we're trying to make sure it's done where worst needed.

MR. ZAMARIN: I know. But not where you leave it so wide that there's -- I mean, we have

to have some control to it. But there again, we don't want to --

MS. FLECK: Alan, this is Sue from National Grid. I think it's the list that bothers us, and if you're saying, or other technology, your list is kind of open anyway, so why even say it? Why can't paragraph 2 or item number 2 just be appropriate mitigating technology. Instead of listing, because it's the list that bothers us. When you put the list in there, somebody might try to hold us accountable to doing every single one of those things, when what you're really trying to do is say, you need to use some kind of technology to mitigate the potentially corrosive gas stream.

MR. DANNER: Right. So, on 2, I would actually propose that it would say: Technology to mitigate corrosive gas stream constituents, which may include product sampling -- and so forth.

MS. FLECK: That's better.

MR. DANNER: Okay. Have you captured that? Would you like it again? Would you like it

one more time? All right.

Paragraph 2 would read: Technology to mitigate the potentially corrosive gas stream constituents -- capital T on Technology, but then say: Such technologies may include product-sampling inhibitor injections, in-line cleaning pinging, and separators.

Okay. Are we there? So we have a motion, and again I'm assuming we can pretend that this is the original motion, without having to vote on an amendment, and we'll just take a roll call on this. You ready for that? Okay, let's take a roll.

MS. WHETSEL: We've all agreed, as amended, the original -- Okay. Yea or nay, everybody. Steve Allen?

MR. ALLEN: Yea.

MS. WHETSEL: Dave Danner?

MR. DANNER: Yes.

MS. WHETSEL: Terry Turpin?

MR. TURPIN: Yea.

MS. WHETSEL: Cheryl Campbell?

MS. CAMPBELL: Yea.

MS. WHETSEL: Andy Drake?

MR. DRAKE: Yea.

MS. WHETSEL: Sue Fleck?

MS. FLECK: Yea.

MS. WHETSEL: Rich Worsinger?

MR. WORSINGER: Yea.

MS. WHETSEL: Chad Zamarin?

MR. ZAMARIN: Aye.

MS. WHETSEL: Smarty. Sara Gosman?

MS. GOSMAN: Yea.

MS. WHETSEL: Robert Hill?

MR. HILL: Yea.

MS. WHETSEL: Okay, and we can say Yea. It's passed.

MR. DANNER: All right, that was easy. So it's now 3:00. Let's take a really fast ten-minute break. We're going to be back here and finish up the afternoon's agenda. Thank you.

(Whereupon, the above-entitled matter went off the record at 2:58 p.m. and resumed at 3:18 p.m.)

Safety of Gas Transmission and Gathering Pipelines

RIN: 2137-AE72
Docket: PHMSA - 2011 – 0023

Gas Pipeline Advisory Committee Meeting

June 6 - 7, 2017

U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration

To Protect People and the Environment From the Risks of Hazardous Materials Transportation

1d. Internal Corrosion
192.478

- **Committee Comments:**
  - Should only be required for lines carrying corrosive gas
  - Some distribution operators rely on suppliers to monitor gas quality and do not own any gas monitoring equipment
  - Monitoring frequency of twice per year is too frequent
  - Need to harmonize with 192.477, which duplicates the proposed 192.478(c)

1d. Internal Corrosion
192.478

- **Based on committee discussion, PHMSA suggests the committee consider:**
  – Provide flexibility for operators to determine the internal corrosion monitoring program by adding "as necessary" and "where applicable" in paragraph (a), as suggested in industry letter docketed April 5, 2017.
  – Address comments on methodology and that some distribution operators rely on suppliers for gas monitoring equipment by modifying (b)(1) as follows: "At points where gas with potentially corrosive contaminants enters the pipeline, the use of gas-quality monitoring methods to determine the gas stream constituents."
  – Address frequency of monitoring and program review by changing frequency from twice per year to once per year.
  – Delete proposed paragraph (c) and refer to 192.477 in 192.478(a).

1d. Internal Corrosion
192.478

Discussion & Vote

- Public Comments
- GPAC discussion and comments on PHMSA suggestions.
- GPAC vote on proposed rule.
  - Start with vote on proposed rule.
  - Accept additional motions as necessary.

Voting Language for Corrosion Control – Internal Corrosion
§ 192.478

Approved GPAC Language 6/6/17

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation, with regard to the provisions for internal corrosion, are technically feasible, reasonable, cost-effective, and practicable if the following changes are made:

- Modify (b)(1) as follows: "At points where gas with potentially corrosive contaminants enters the pipeline, the use of gas-quality monitoring methods to determine the gas stream constituents."
- Change frequency of monitoring and program review from twice per year to once per calendar year, not to exceed 15 months.
- Delete proposed paragraph (c) and refer to 192.477 in 192.478(a).
- Limit the applicability of paragraph (a) to the transportation of corrosive gas. PHMSA will provide additional guidance based on the GPAC discussion.
- Revise (b)(2) to read "Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling and inhibitor injections."

Safety of Gas Transmission and Gathering Pipelines

RIN: 2137-AE72
Docket: PHMSA - 2011 – 0023

Gas Pipeline Advisory Committee Meeting

December 14 - 15, 2017

U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration

To Protect People and the Environment From the Risks of Hazardous Materials Transportation

7d. Strengthened Assessment Requirements SCCDA
192.923(c) & 192.929
NPRM Comments

- NACE recommendations should not be mandatory.
- **PHMSA**: Recommendations in the standard are items operators should do and PHMSA seeks to codify that expectation, as applicable.
- Include reference to ASME/ANSI B31.8S (incorporated by reference, see 192.7), appendix A3 for susceptibility criteria.
- **PHMSA**: ASME B31.8S is currently referenced in 192.929, but the NACE SP 0204 is a much more comprehensive standard and PHMSA believes incorporating the NACE standard will provide improved and more consistent SCCDA results.

7d. Strengthened Assessment Requirements SCCDA 192.923(c) & 192.929

NPRM Comments

- Commenter recommended that proposed language be deleted and SCCDA be conducted per NACE SP0204-2008 with only those additional items currently in 192.929, but PHMSA should not exceed those established industry standards. For example, proposed rule would require minimum of two above-ground surveys and three direct examinations. These additional requirements do not account for operators who utilize other sources of information, such as ILI runs, to compliment SCCDA results.

- **PHMSA:** proposes to supplement NACE with additional requirements to address specific issues that could adversely affect SCCDA results. Operators that desire to deviate from assessment requirements could submit an "other technology" notification to PHMSA.

U.S. DEPARTMENT OF TRANSPORTATION

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PIPELINE AND HAZARDOUS MATERIALS
SAFETY ADMINISTRATION

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GAS PIPELINE ADVISORY COMMITTEE MEETING

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FRIDAY
MARCH 2, 2018

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The Advisory Committee met via teleconference at 10:10 a.m., Hon. Diane Burman, Acting Chair, presiding.

MEMBERS PRESENT

HON. DAVID W. DANNER, Washington Utilities and Transportation Commission; Chair
STEPHEN E. ALLEN, Indiana Utility Regulatory Commission
RONALD A. BRADLEY, PECO Energy
HON. DIANE BURMAN, New York State Public Service Commission
CHERYL F. CAMPBELL, Xcel Energy Incorporated
ANDREW J. DRAKE, Enbridge Gas Transmission
SARA ROLLET GOSMAN, Pipeline Safety Trust; University of Arkansas School of Law
RICHARD F. PEVARSKI, Virginia Utility Protection Services LLC/Virginia 811
RICHARD H. WORSINGER, Public Utilities, City of Rocky Mount, North Carolina
CHAD J. ZAMARIN, Williams Companies

But we believe our experience supports the idea that perhaps there is a more focused approach to scheduling repairs for these type of flaws.

I certainly wouldn't argue that this type of a flaw shouldn't be addressed, I am simply indicating that it would seem that there is the opportunity anyways to have a more focused analysis and that way we can keep our resources primarily focused on immediate safety threats.

I appreciate the time today to speak with you this afternoon and thank you for all of your hard work. I am really impressed with the way the Rule is shaping up and I very much appreciate the difficulty of the process. Thank you.

MS. BURMAN: Thank you for that, Mark. Next up we have Pat Carey. Pat, if you can do Star 1.

OPERATOR: Pat Carey, your line is open, please go ahead.

MR. CAREY: Okay, thank you. As the

Chairman has indicated this is Patrick Carey. I am with Kinder Morgan and I want to talk some comments relative to the cracking criteria and specifically we feel that the reference within the definitions of significant cracking should be removed.

What such thing is proposed in the alternative cracking criteria for metal loss is a much better criteria and is sufficient for the designation of the stress corrosion, crack and selective seam weld corrosion, and seam cracking.

And the other criteria that we have with the significant cracks is not really reflective or representative of the severity of the anomaly, which would be in those cases described by the maximum depth or failure pressure ratios that the operators wouldn't schedule responses for these anomalies based on the alternative criteria for these cracks in accordance with the ASME B31.8S, Section 7.2-4 for volumetric anomalies like we do for selective seam and weld corrosion.

In addition to that, in the alternative cracking criteria which was detailed in Slide 91, specifically on Item C, we feel that the assessment models have a lot of conservative built into them already and that if a crack is predicted to grow to less than 125 percent of MAOP it being an immediate is really overly conservative.

A more appropriate threshold for this immediate response criteria should be the 1.1. We're already growing these cracks to the point where if we hit the 139 percent that we are going to be scheduling in the one to two year timeframe and growing in that period between the determination of the anomaly in the next assessment to 125 percent is really going to be, again, overly conservative and redundant. That's all I have for comment.

MS. BURMAN: Thank you, Pat. Next up is Jim Shafer. Jim, if you can do Star 1.

OPERATOR: Jim, your line is open, please go ahead.

Safety of Gas Transmission and Gathering Pipelines

RIN: 2137-AE72

Docket: PHMSA - 2011 – 0023

Gas Pipeline Advisory Committee Meeting

March 2, 2018

U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration

To Protect People and the Environment From the Risks of Hazardous Materials Transportation

4. Repair Criteria Revisions

Existing Anomaly Type HCA Only	Existing Timing HCA Only	NPRM Anomaly Type Applies to both HCA and Non-HCA	NPRM Timing Applies to both HCA and Non-HCA
Predicted Failure Pressure (PFP) ≤ 1.1 x MAOP	Immediate	PFP ≤ 1.1 x Maximum Allowable Operating Pressure (MAOP) (same for HCA, new for non-HCA)	Immediate
Dent w/Metal Loss (ML), cracking, or stress riser	Immediate	Dent w/ML, cracking, or stress riser (same)	Immediate
Any other anomaly requiring immediate action	Immediate	Any other anomaly requiring immediate action (same)	Immediate
(no current requirement)		Metal loss >80%	Immediate
		Metal loss affecting DC/LF/HF ERW/EFW seam	Immediate
		Significant SCC	Immediate
		Significant SSWC	Immediate

4. Repair Criteria Revisions
192.711, 192.713, 192.933
NPRM Comments

- Revise paragraph 192.933(d)(1)(v) to allow for fitness for service evaluation and clarify that this is specific to selective seam weld corrosion rather than general corrosion crossing the seam weld. High frequency electric resistance welded (HF-ERW) pipe is considered "ductile" and thus should not be included in this category.
- **<u>PHMSA</u>:** Based on incident investigation, experience, and data, PHMSA believes the proposed repair criteria is appropriate and inclusion of HF-ERW pipe seam welds in 192.933(d)(1)(v) is appropriate. See seam failure incident data on next slide.

4. Repair Criteria Revisions
192.711, 192.713, 192.933
NPRM Comments
Pipe Seam Failures (2010-Nov. 2017)

Pipe Seam Type	Gas Transmission Incidents Caused by Material Failure of Pipe or Weld
Flash Welded	17
Lap Welded	4
Longitudinal ERW - High Frequency	10
Longitudinal ERW - Low Frequency	15
Longitudinal ERW - Unknown Frequency	10

BEFORE THE
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
WASHINGTON, D.C.

Pipeline Safety: Meeting of Gas Pipeline Safety Advisory Committee	Docket Nos. PHMSA-2016-0136, PHMSA-2011-0023

COMMENTS ON PHMSA GAS PIPELINE ADVISORY COMMITTEE (GPAC) TELECONFERENCE HELD MARCH 2, 2018

FILED BY
AMERICAN GAS ASSOCIATION
AMERICAN PETROLEUM INSTITUTE
AMERICAN PUBLIC GAS ASSOCIATION
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

March 9, 2018

I. Introduction

The American Gas Association (AGA)[1], American Petroleum Institute (API)[2], American Public Gas Association (APGA)[3] and Interstate Natural Gas Association of America (INGAA)[4] (jointly "the Associations") submit these comments for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA) concerning the fourth Gas Pipeline Advisory Committee (GPAC) meeting on the Safety of Gas Transmission & Gathering Lines Rulemaking (Proposed Rule)[5] that occurred via teleconference on March 2, 2018.[6] The GPAC meetings provide the GPAC Members, PHMSA representatives, the regulated community, and the public the opportunity to discuss topics contained within the Proposed Rule.

The Associations also provided PHMSA and the GPAC members with comments following the previous three GPAC meetings on this rulemaking[7] that were intended to summarize the views expressed during the meetings and elaborate on the concerns identified. Additionally, the Associations provided markups to the proposed regulatory text that were intended to mirror the votes and discussions held by the GPAC and to identify outstanding concerns. The following comments on the March 2, 2018 GPAC teleconference are similar in content and structure.

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[1] The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 72 million residential, commercial and industrial natural gas customers in the U.S., of which 94 percent — over 68 million customers — receive their gas from AGA members. Today, natural gas meets more than one-fourth of the United States' energy needs.

[2] API is the national trade association representing all facets of the oil and natural gas industry, which supports 9.8 million U.S. jobs and 8 percent of the U.S. economy. API's more than 650 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 25 million Americans.

[3] APGA is the national, non-profit association of publicly-owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has over 700 members in 37 states. Overall, there are nearly 1,000 municipally-owned systems in the U.S. serving more than five million customers. Publicly-owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

[4] The Interstate Natural Gas Association of America (INGAA) is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry in North America. INGAA's members represent the vast majority of the interstate natural gas transmission pipeline companies in the United States, operating approximately 200,000 miles of pipelines, and serve as an indispensable link between natural gas producers and consumers.

[5] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 29830 (May 13, 2016).

[6] Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 83 Fed. Reg. 6087 (February 12, 2018). The GPAC is a peer review committee charged with providing recommendations on the technical feasibility, reasonableness, cost-effectiveness, and practicability of PHMSA's proposed safety standards for gas pipeline facilities. 49 U.S.C. §§ 60102(b)(2)(G), 60115.

[7] Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 81 Fed. Reg. 83795 (November 22, 2016), held January 11-12 2017, Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 82 Fed. Reg. 23714 (May 23, 2017), held June 6-7 2017, and Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 82 Fed. Reg. 51760 (November 7, 2017), held December 14-15 2018.

The Associations also remind PHMSA of the discussion at the December 2017 GPAC meeting around the importance of PHMSA providing appropriate conservative Charpy toughness values.[13] PHMSA's proposed values (5.0 ft-lb for body toughness and 1.0 ft-lb for seam toughness) are inappropriately conservative. Per "Structural Integrity Associates, Statistical Evaluation of Charpy Toughness Levels for Gas Transmission Pipelines, Report No. 1600513.401, July 2016," PHMSA should allow operators to use 13.0 ft-lb for body toughness and 4.0 ft-lb for seam toughness, when toughness data is not available.

The Associations propose that the required material properties for volumetric anomaly response calculations are grade, diameter, and wall thickness. Similarly, for planar anomalies, including crack features, the required material properties for anomaly response calculations are grade, diameter, wall thickness, and toughness.

2) PHMSA should introduce a mechanism that allows operators to use engineering analysis prior to responding to dents with metal loss and metal loss preferentially affecting the long seam to demonstrate that an indicated anomaly does not pose a risk to pipeline integrity.

In the proposed rule, PHMSA would allow operators to perform an engineering analysis to differentiate metal loss and cracking conditions that require a response (proposed §192.713(d)(1)(i) and §192.933(d)(1)(i) and PHMSA "alternative cracking criterion"), but does not allow a similar analysis for dent anomalies with metal loss or metal loss anomalies preferentially affecting the long seam. By allowing operators to perform engineering analysis on anomalies based on inline inspection data, many unnecessary digs of non-injurious anomalies can be avoided. This will allow operators to focus their resources on threats that present higher risk to their pipelines and avoid unnecessary disruptions to customers and landowners. An engineering analysis should be based on a publicly available and commonly used study, approved standard, or practice available for guidance in addressing pipeline integrity.

The capabilities of inline inspection tools have improved dramatically over the past 15 years and the requirement to respond immediately to "a dent that has any indication of metal loss" no longer reflects these capabilities.[14] The language in PHMSA's existing anomaly response regulations, originally published in 2003, does not take into account advancements in inline assessment technology and is not aligned with published technical standards in some instances. Technology advancements include improvements in tool sensitivity and detection limits, anomaly sizing accuracy, and differentiation between anomaly types. Many of the "indications" that modern inline inspection tools can now identify represent small amounts of metal loss that present minimal public risk. In the past these non-injurious anomalies were often not detected using older technologies. In many cases, small metal loss existed during the previous ILI runs, but the tools and analysis at the time were not sensitive enough to detect it. These indications do not need to be repaired immediately, since the features have likely existed for years, sometimes even decades, and are stable. When utilizing higher-capability, higher-sensitivity tools, there is also the

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[13] See comments of Member Drake (12/15/17 transcript, page 9 – 10): "you know, the assumption of fracture toughness at five and one foot pounds is very, very conservative. And I think operators will have other data and other means of collecting more conservative numbers….Someone said something of 13 and four. Those are also very conservative, but a little more practicable."

Mr. Nanney with PHMSA: "All right. Yes. We were planning to do that."

[14] For a brief review of historical, present and future ILI capabilities, *see*: Rau J, Kirkwood M. Hydrotesting and In-Line Inspection: Now and in the Future. ASME. International Pipeline Conference, Volume 1: Pipelines and Facilities Integrity ():V001T03A055. doi:10.1115/IPC2016-64105.

potential for false-positive indications.[15] Simply put, "any indication" means something very different today than it did when the anomaly response regulations were adopted approximately fifteen years ago, and is no longer an appropriate threshold for making anomaly response decisions.

The Associations conducted a comprehensive review of all onshore gas transmission pipelines incidents (inside and outside of HCAs) reported to PHMSA from 2010-2016. This review identified 9 dent-related incidents during this period, which is approximately 1% of all onshore gas transmission pipeline incidents during this period. None of these incidents involved injuries or fatalities. The low frequency of incidents caused by dents supports the Associations' proposal to add an engineering analysis approach as an alternative for managing these anomalies as monitored conditions. Many operators are currently expending significant resources to respond immediately to every dent that has any indication of metal loss on pipeline segments in HCAs. These costs will rise substantially if this criterion is extending outside of HCAs and the costs are not commensurate with the risk associated with these anomalies. The Associations estimate that pipeline operators would incur additional costs of $50 million - $100 million per year addressing dents that have any indication of metal loss if this specific existing requirement is extended to all pipeline segments. Furthermore, since PHMSA currently proposes to require immediate response to all dent anomalies with any indication of metal loss, this will result in significant customer disruptions as operators will be required to take immediate pressure reductions while each one of these anomalies is excavated for examination and potential repair.

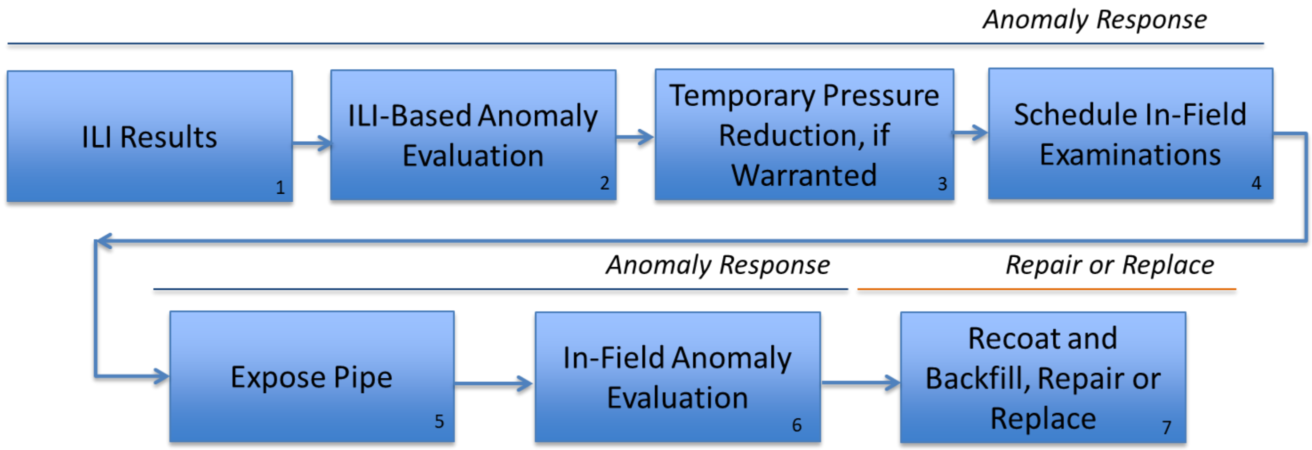
The potential expansion of dent anomaly response criteria to all pipeline segments amplifies the need for technically-supported, risk-appropriate response criteria. Adopting the Associations' proposed engineering analysis alternative would allow operators to focus resources on threats that present higher risk to their pipelines, instead of addressing non-injurious anomalies.

3) PHMSA should clarify the terminology used in §192.713 and §192.933 and that the timelines prescribed are for the operator's response, not remediation.

Both existing and proposed requirements for the response to, and repair of, potential pipeline anomalies do not recognize the important differences between actions that operators take when evaluating the results of integrity assessments versus those actions that operators take following in-field examinations of potential anomalies. The criteria in proposed §§ 192.713(d) and 192.933(d) titled "<u>Remediation schedule</u>" actually provide operators with the requirements related to anomaly <u>response</u>; i.e., these requirements describe when the operator must schedule an in-field examination to evaluate a condition discovered through integrity assessment and determine the remaining strength of the pipeline. The evaluation may include considerations for a temporary pressure reduction to ensure continued safe operation. <u>Repairs</u> are made after the operator has physically examined and evaluated the potential pipeline anomaly in the field. To avoid confusion and align with operator practices, the Associations propose adding a separate <u>repair</u> criteria paragraph within §§ 192.713 and 192.933.

After an integrity assessment, an operator follows a stepwise process to respond to the assessment findings, followed by an in-field examination and then, based on the examination results, the operator may conduct repairs. This process is depicted below:

[15] For example, on a pipe without any anomalous conditions, an inline inspection tool may call out a small "indication" of an anomalous condition within its accuracy range.



Integrity assessments provide information on conditions that may require further investigation – operators determine whether a response is required based on this information. The actual characteristics of that condition, and whether it requires repair or remediation, cannot be established without the operator conducting a physical in-field examination (a "dig") and evaluating the results of that examination. In many cases, anomalies that appear to require a repair based on initial indirect tool measurements, such as indications from an ILI report (e.g., immediate conditions), do not require repair once the anomaly is excavated, physically examined, and evaluated in the field. This is because assessment technologies use indirect measurements to infer conditions on the pipeline rather than directly measure them. Because of the limitations of these technologies compared to physical in-field examinations, the conditions (e.g. – length, depth, interaction of indications, etc.) "as called" by an assessment technology that warrant excavation and examination may be different than those conditions "found" once the anomaly has been physically examined and evaluated.

4) PHMSA should make specific modifications to align the anomaly response criteria with consensus technical standards and current technologies.

In the next section of these comments, the Associations recommend specific modifications to PHMSA's proposed regulatory text to align the anomaly response criteria with consensus technical standards and current technology capabilities. To summarize, the Associations recommend the following changes:

Dents with metal loss: Only a dent with metal loss on the top of the pipeline (8 o'clock to 4 o'clock – top two-thirds) should be an immediate response condition, as dents due to mechanical damage are most likely to occur on the top of the pipe. Gouging caused by mechanical damage is much more difficult to size and evaluate reliably. In light of these difficulties, a more conservative approach is warranted for dents with metal loss that are more likely to be due to mechanical damage.

Research and consensus technical standards support the need for immediate repair of dents with metal loss due to mechanical damage (i.e., a scratch, gouge, or stress riser), but NOT where metal loss is due to corrosion. A dent with metal loss on the bottom of a pipeline (4 o'clock to 8 o'clock – bottom one-third) should be a scheduled response condition, as the metal loss is more likely to be due to corrosion on the bottom of the pipe and bottom-side dents are typically constrained by the feature causing the dent (e.g., a rock, ledge or other material). As discussed above, a dent with indication of metal loss, cracking, or a

stress riser should be a monitored condition if engineering analysis demonstrates that the dent is non-injurious.

Metal loss anomalies should be scheduled for response based on predicted failure pressure ratios in accordance with ASME B31.8S - 2004 Section 7, Figure 4 (Figure 7.2.1-1 in editions since 2012), consistent with current requirements for pipelines segments in HCAs. PHMSA has added a one-year (HCA) and two-year (non-HCA) condition related to the calculation of predicted failure pressure ratios and class location design factors. The ratios proposed by PHMSA, based on class location design factors, are contrary to those ratios that would require a one or two-year response per ASME B31.8S. The addition of the class location factor adds a redundant safety margin in addition to that already provided in B31.8S, and would result in unnecessary excavation of small metal loss anomalies. PHMSA's proposal is presented with no supporting data or analyses to demonstrate either the need or the effectiveness of the proposed change. Furthermore, PHMSA has not clarified how this requirement would be applied for segments where a class location change has occurred. For segments designed to the class 1 design factor (.72) but where there has been a "class bump" to class 2 in accordance with §192.611, a requirement to apply PHMSA's new 1.39 factor in anomaly response and repair calculations could cause *any* metal loss anomaly to require response/repair.

Cracks or crack-like defects should be evaluated using well-established fracture mechanics modeling methods to calculate failure pressures. The Associations remind PHMSA of our previously-submitted comments on PHMSA's proposed language for the fracture mechanics modeling process. PHMSA's proposed fracture mechanics modeling language (proposed § 192.624(d)) is extremely convoluted and must be rewritten for clarity. As currently drafted, the proposed language is unclear as to the required data inputs, methods and considerations for performing fracture mechanics modeling. The Associations recommended that PHMSA create a new section, § 192.712, to describe requirements for the fracture mechanics modeling process, and the Associations have recommended specific language for proposed § 192.712 to ensure clear and effective requirements. The Associations' recommended language for fracture mechanics modeling is included in the next section.

Following fracture mechanics modeling, response schedules should then be established based on failure pressure ratios consistent with the framework in API RP 1176. PHMSA should require immediate response where crack depth plus corrosion is greater than 70% of pipe wall thickness or greater than the inspection tool's maximum measurable depth, or where the anomaly is determined to have a predicted failure pressure ratio less than or equal to 1.1xMAOP. PHMSA should require one-year (HCA) or two-year (non-HCA) response where crack depth plus corrosion is greater than 50% of pipe wall thickness or the anomaly is determined to have a predicted failure pressure ratio less than or equal to 1.25xMAOP.

Definitions of Significant cracking: The Associations recommend that PHMSA remove the references to and definitions for "significant cracking." PHMSA's proposed "alternative cracking criterion" is the correct approach. The "significant" designation for stress corrosion cracking (SCC), selective seam weld corrosion (SSWC) and seam cracking is not representative of the severity of the anomaly, which is described by maximum depth or failure-pressure ratio. For example, the 10% crack depth threshold for seam cracks is overly conservative; for new pipe, gas transmission pipeline operators have employed manufacturing/construction procedures which have an acceptance limit of 10% depth for crack-like weld seam anomalies. The "significant seam cracking" definition as proposed would therefore require these operators to respond to like-new pipe as an immediate condition. Such anomalies certainly do not meet the intent of the immediate response threshold in ASME B31.8S: an assessment indication that warrants an immediate response is one that "shows the defect is at a failure point" and "might be expected to

UNITED STATES DEPARTMENT OF TRANSPORTATION

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PIPELINE AND HAZARDOUS MATERIALS
SAFETY ADMINISTRATION

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GAS PIPELINE ADVISORY COMMITTEE

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TUESDAY
MARCH 27, 2018

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The Gas Pipeline Advisory Committee met in the Ballroom of the Hilton Arlington, 950 North Stafford Street, Arlington, Virginia, at 8:30 a.m., David Danner, Chair, presiding.

PRESENT

DAVID W. DANNER, Chair
W. JONATHAN AIREY, Member
STEPHEN E. ALLEN, Member
RONALD A. BRADLEY, Member
DIANE BURMAN, Member (via teleconference)
J. ANDREW DRAKE, Member
SARA ROLLET GOSMAN, Member
ROBERT W. HILL, Member
SARA W. LONGAN, Member
TERRY L. TURPIN, Member

RICHARD H. WORSINGER, Member

committee comment on repair criteria on our March 2, 2018 meeting. Use of class location safety factors for calculation of a short-term pressure reduction as a safety precaution in response to an immediate condition is too conservative.

PHMSA's response, PHMSA suggests modifying Section 713(d)(2) to strike the phrase the lower of. The effect would be that operators would not always be required to use the class location factors when --

(Technical interference.)

MR. NANNEY: Hello? Now it came back on. Okay.

Our operators may choose to use either the calculated safe operating pressure based on class location, 80 percent of the operating pressure at the time of the discovery, or 1.1 times the predicted failure pressure based upon situational safety impacts to the public and operator personnel.

Going to slide 148, and this is comments on specific repair criteria for dents.

Slide 149, and again, this is public committee comments on repair criteria on dents from March 2, 2018. PHMSA should allow operators to use ECA, engineering critical analysis or assessment, to evaluate dents.

PHMSA's response, the original repair criteria for dents were developed in the early 2000 timeframe for both hazardous liquid and gas integrity management rules. Both in-line inspection technology and analytical techniques to assess dents have advanced significantly since that time.

PHMSA has gained confidence in applying ECA techniques to analyze dent defects through recent application of dent ECA and special permits.

Consistent with applying proven analytical techniques to evaluate corrosion metal loss and cracking defects, PHMSA suggests including a dent ECA procedure in the final rule as shown on the next slide.

Slide 150, and again, this is PHMSA's

US DEPARTMENT OF TRANSPORTATION

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PIPELINE AND HAZARDOUS MATERIALS
SAFETY ADMINISTRATION

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GAS PIPELINE ADVISORY COMMITTEE

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WEDNESDAY
MARCH 28, 2018

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The Gas Pipeline Advisory Committee met in the Ballroom of the Hilton Arlington, 950 North Stafford Street, Arlington, Virginia, at 8:30 a.m., David Danner, Chair, presiding.

PRESENT

DAVID W. DANNER, Chair
W. JONATHAN AIREY, Member
STEPHEN E. ALLEN, Member
RONALD A. BRADLEY, Member
DIANE BURMAN, Member (via telephone)
J. ANDREW DRAKE, Member
SARA ROLLET GOSMAN, Member
ROBERT W. HILL, Member
SARA W. LONGAN, Member
TERRY L. TURPIN, Member

RICHARD H. WORSINGER, Member

line represented 11 percent of the data. So we had a total of 143 immediate responses over the course of 3,500 miles of HCAs in that five-year time frame. Again, 11 percent or I guess that translates to about 14 or 15 of the immediate responses were on that one particular line.

The other 5 percent were some miscellaneous results; I don't have the details on those.

MR. DANNER: All right. Thank you. Yes, sir?

MR. OSMAN: CJ Osman with INGAA. I had a few other data points I'd like to share that may help inform the discussion on this topic. Several folks have already covered some of the concerns around whether the immediate response data is appropriate to reference and to try to respond to here.

I think the other important thing to look at is the actual incident data. What's good about the incident data is we can really drill into what caused the different incidents. And if

we look at the corrosion incident trends going back to 2010, over 70 percent of those incidents occur on lines that have not had in-line inspection. These requirements talk about what you do after you perform in-line inspection and then respond to those anomalies.

So I don't think changing the anomaly response and repair criteria is going to have a major impact on internal/external corrosion incidence. So I think that's important to consider, too, in looking at whether it really makes sense to change the corrosion and metal loss response criteria.

Also, on a related note, there's a criteria proposed to a requirement related to metal loss affecting the long seam. And we went back and looked at data from 2010 to 2017 and found zero corrosion or environmental corrosion metal loss incidents affecting the long seam of high frequency ERW pipes. Those pipes are not known to be particularly susceptible to this type of corrosion, so based on that incident review

and our knowledge of this type of seam, we don't think high frequency ERW pipes should be included in the response and repair requirements related to metal loss preferentially affecting the long seam. Thank you.

MR. DANNER: All right. Thank you. Are there any other public comments on this topic? All right. Seeing none, open it up to the Committee for -- oh, should we go ahead? Okay. So we are going to take a lunch break right now. It is 11:49. We'll come back at 1:00. So see you all then.

(Whereupon, the above-entitled matter went off the record at 11:49 a.m. and resumed at 1:12 p.m.)

MR. DANNER: All right. We're back on the record. We're going to continue our discussion of corrosion metal loss criteria. I'm going to turn it over to Alan.

MR. MAYBERRY: Okay. Thanks, Mr. Chairman. If you recall, where we left off was on corrosion. We had ended with public comment

Safety of Gas Transmission and Gathering Pipelines

RIN: 2137-AE72
Docket: PHMSA - 2011 – 0023

Gas Pipeline Advisory Committee Meeting

March 26 - 28, 2018

U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration

To Protect People and the Environment From the Risks of Hazardous Materials Transportation

6. Repair Criteria
192.485(c); 192.711; 192.713; 192.933

Comments on Specific Repair Criteria
DENTS

6. Repair Criteria
192.485(c); 192.711; 192.713; 192.933

Public/Committee Comments on Repair Criteria (3/2/18):

- PHMSA should allow operators to use ECA to evaluate dents.
- **PHMSA**: the original repair criteria for dents were developed in the early 2000s timeframe for both HL and gas integrity management rules.
- Both ILI technology and analytical techniques to assess dents have advanced significantly since that time. PHMSA has gained confidence in applying ECA techniques to analyze dent defects through recent application of dent ECA in special permits.
- Consistent with applying proven analytical techniques to evaluate corrosion metal loss and cracking defects, PHMSA suggests including a dent ECA procedure in the final rule as shown on the next slide.

6. Repair Criteria
192.485(c); 192.711; 192.713; 192.933

Public/Committee Comments on Repair Criteria (3/2/18):

- **PHMSA**: **Summary of suggested ECA for Denting:**
  - Evaluate potential threats for the pipe segment in the vicinity of the dent including movement, loading, and cathodic protection;
  - Review HR-MFL and HR-Deformation inline inspection data for damage in the dent area and any associated weld region;
  - Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data;
  - Compare dent profile between the recent and past HR-Deformation inspections to identify significant changes in dent depth and shape; (cont.)

6. Repair Criteria
192.485(c); 192.711; 192.713; 192.933

Public/Committee Comments on Repair Criteria (3/2/18):

- **PHMSA**:
  Summary of suggested ECA for Denting (cont.)**:**
  - Identify and quantify all loads acting on the dent for a basis for ECA;
  - Evaluate strain level associated with dent and any welds using Finite Element Analysis (FEA), and calculate the plastic strain limit damage factors to infer the possibility of a crack;
  - Estimate the fatigue life of the dent using FEA with the operational pressure data and different fatigue life prediction models, which must have reassessment safety factor of 2.

6. Repair Criteria
192.485(c); 192.711; 192.713; 192.933

Public/Committee Comments on Repair Criteria (3/2/18):

- PHMSA should allow operators to use ECA to evaluate dents.
- **PHMSA**: (cont.)
  PHMSA suggests that operators be allowed (but not required) to use ECA analysis for the following dent-related repair criteria:
  - Dent with indication of metal loss, cracking, or stress riser
  - Smooth topside dent > 6% diameter (or 0.50 in. deep for D<NPS12)
  - Dent > 2% diameter (or >0.25 in. deep for D<NPS12) that affects pipe curvature at a girth weld or seam weld
- Dents analyzed by ECA, but shown to not exceed critical strain levels would be included in the repair criteria as Monitored Conditions.

6. Repair Criteria
192.485(c); 192.711; 192.713; 192.933

Public/Committee Comments on Repair Criteria (3/2/18):

- Repair criteria for dents with metal loss should distinguish between topside and bottom-side dents (similar to the repair criteria for smooth dents).
- **PHMSA**:
  - The dent with metal loss criterion was part of the original integrity management (IM) rule (2003).
  - PHMSA recognizes that topside dents represent the need for a more urgent response than bottom-dents. Some existing HCA dent repair criteria already make this distinction.
  - PHMSA suggests applying this concept to dents with metal loss in non-HCA locations (similar to smooth dents). (cont.)

6. Repair Criteria
192.485(c); 192.711; 192.713; 192.933

Public/Committee Comments on Repair Criteria (3/2/18):

- Repair criteria for dents with metal loss should distinguish between topside and bottom-side dents (similar to the repair criteria for smooth dents). (cont.)
- **PHMSA**: (cont.) Also, to reduce unnecessary excavations, PMSA suggests revising this immediate condition as follows:
  - Allow engineering critical assessment (ECA) to analyze dent anomalies with indications of metal loss, cracking or stress riser, and prioritize repair criteria as follows:
  - Immediate: topside defects that exceed critical strain levels,
  - 2 Year: bottom-side that exceed critical strain levels, and
  - Monitored: defects that do not exceed critical strain levels.

6. Repair Criteria
192.485(c); 192.711; 192.713; 192.933

Public/Committee Comments on Repair Criteria (3/2/18):

- Industry commented that the proposed criterion of a gouge or groove greater than 12.5% of nominal wall thickness is duplicative and addressed by the dent with metal loss and cracking criteria.

- **PHMSA**: acknowledges that the proposed criteria using engineering critical assessment to analyze dents and cracks would adequately address gouges and grooves and suggests deleting this repair criterion on that basis.

6. Repair Criteria Revisions
192.485(c); 192.711, 192.713, 192.933

- **Public/Committee Comments on Repair Criteria (3/2/18):**
- Industry commented that PHMSA's proposed criteria for immediate repair of crack defects was too conservative and suggested 70% crack depth or predicted failure pressure of less than 1.1 x MAOP.
- **PHMSA**: based the proposed immediate repair criteria for cracks on successful application of comparable criteria in special permits.
- PHMSA believes 70% and 1.1 x MAOP do not provide an adequate safety margin.
  - ILI tools for detection of cracks do not have the precision needed to allow through wall cracks slightly < 70% or a calculated PFP slightly > 1.1 x MAOP to be treated as 1-yr (HCA)/2-yr (non-HCA) conditions.
  - Cracks can grow very rapidly.
  - Material properties can have a dramatic affect on safe pressures, as illustrated on the next slide.

6. Repair Criteria Revisions
192.485(c); 192.711, 192.713, 192.933

- **Public/Committee Comments on Repair Criteria (3/2/18):**
- Industry commented that PHMSA's proposed criteria for immediate repair of crack-like defects was too conservative and suggested 70% crack depth or predicted failure pressure of less than 1.1 x MAOP.
- **PHMSA**: (cont.) Based on successful application of comparable cracking criteria, PHMSA suggests the following crack criterion for an immediate condition:
  - (A) Crack depth plus metal loss > 50% of pipe wall thickness; or
  - (B) Crack depth plus any corrosion is greater than the inspection tool's maximum measurable depth; or
  - (C) The crack anomaly is determined to have (or will have prior to the next assessment) a predicted failure pressure (determined in accordance with the ECA fracture mechanics procedure) that is less than 125% of the MAOP.

6. Repair Criteria Revisions
192.485(c); 192.711; 192.713; 192.933

- **In light of public comments received on the NPRM, and committee comments from the March 2, 2018 meeting, PHMSA suggests the Committee consider:**

- **PHMSA**: suggests revising this immediate condition for non-HCAs as follows:
  - Allow engineering critical assessment (ECA) to analyze dent anomalies with indications of metal loss, cracking or stress riser, and prioritize repair criteria as follows:
  - **Immediate**: topside defects that exceed critical strain levels,
  - **2 Year**: bottom-side that exceed critical strain levels, and
  - **Monitored**: defects that do not exceed critical strain levels.

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Voting Language for 6-Month Grace Period for Reassessments

§ 192.939

Approved GPAC Language 1/12/17

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation, with regard to the provision for 6-month grace periods for the reassessment intervals, are technically feasible, reasonable, cost-effective, and practicable.

Voting Language for Corrosion Control – Internal Corrosion
§ 192.478

Approved GPAC Language 6/6/17

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation, with regard to the provisions for internal corrosion, are technically feasible, reasonable, cost-effective, and practicable if the following changes are made:

- Modify (b)(1) as follows: "At points where gas with potentially corrosive contaminants enters the pipeline, the use of gas-quality monitoring methods to determine the gas stream constituents."
- Change frequency of monitoring and program review from twice per year to once per calendar year, not to exceed 15 months.
- Delete proposed paragraph (c) and refer to 192.477 in 192.478(a).
- Limit the applicability of paragraph (a) to the transportation of corrosive gas. PHMSA will provide additional guidance based on the GPAC discussion.
- Revise (b)(2) to read "Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling and inhibitor injections."

Voting Language for Strengthening IM Assessment Methods

ICDA - §§ 192.923 (b) & 192.927; SCCDA - § § 192.923 (c) & 192.929; Guided Wave Ultrasonics – Appendix F; Passage of ILI Devices - § 192.150

Approved GPAC Language 12/15/17

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation, with regard to the provisions for ICDA, SCCDA requirements, Guided Wave Ultrasonics testing, and the passage of ILI devices, are technically feasible, reasonable, cost-effective, and practicable, if the following changes are made:

- Revise §§ 192.923 (b & c), 192.927, and 192.929 according to the recommendations by PHMSA staff at the meeting, per PHMSA's slides.
- Revise the "no objection" process as recommended by members at the GPAC meeting per the recommended procedure under § 192.607 and considering the other recommendations made regarding the GWUT process by members Drake and Zamarin.

Voting Language for Repair Criteria - § § 192.485(c); 192.711; 192.713; 192.933

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation, with regard to provisions for dent repair criteria, are technically feasible, reasonable, cost-effective, and practicable, if the following changes are made:

- Allowing (but not require) ECA analysis for the following dent-related repair criteria (HCA and non-HCA):
  - Dent with indication of metal loss, cracking, or stress riser
  - Smooth topside dent > 6% diameter (or 0.50 in. deep for D<NPS12)
  - Dent > 2% diameter (or >0.25 in. deep for D<NPS12) that affects pipe curvature at a girth weld or seam weld
  - Dents analyzed by ECA, but shown to not exceed critical strain levels would be Monitored Conditions; PHMSA will consider language to accommodate alternative ECA methods such as FEA

- Revise the immediate condition for dent anomalies with indications of metal loss, cracking, or stress risers in non-HCAs as follows:
  - Allow an engineering critical assessment (ECA) to analyze dent anomalies with indications of metal loss, cracking or stress risers, and prioritize repair criteria as follows:
  - **Immediate**: topside defects that exceed critical strain levels,
  - **2 Year**: bottom-side that exceed critical strain levels, and
  - **Monitored**: defects that do not exceed critical strain levels.

Approved GPAC Language 3/28/18

Voting Language for Repair Criteria - § § 192.485(c); 192.711; 192.713; 192.933

- Consider the below Cracking Repair Criteria for immediate conditions:
  - Crack depth plus corrosion > 50% of pipe wall thickness;
  - Crack depth plus any corrosion is greater than the inspection tool's maximum measurable depth; or
  - The crack anomaly is determined to have ~~(or will have prior to the next assessment)~~ a predicted failure pressure (PFP) that is less than 1.25 x MAOP
  - PHMSA will consider 1.1 x MAOP for immediate conditions after tool tolerance has been field verified and applied.
  - Clarify that material records necessary for evaluating crack defects are determined and documented in accordance with § 192.712.

- Consider the below Cracking Repair Criteria for 1-yr (HCA) and 2-yr (non-HCA) conditions:
  - Crack depth plus corrosion > 50% of pipe wall thickness
  - The crack anomaly is determined to have ~~(or will have prior to the next assessment)~~ a predicted failure pressure (PFP) that is less than 1.39 times MAOP (for class 1 or 2) or 1.50 time MAOP (for other class~~es~~ ~~2,~~ 2 2, 3 and 4)~~, or could grow to an immediate condition (1.25 times or less of MAOP) prior to the next assessment.~~
  - Crack anomalies that do not meet either the Immediate or 1-yr/2-yr conditions would be a Monitored Condition.

Approved GPAC Language 3/28/18

Voting Language for Repair Criteria - § § 192.485(c); 192.711; 192.713; 192.933

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation, with regard to provisions for corrosion metal loss repair criteria, but excluding the anomaly repair timing, are technically feasible, reasonable, cost-effective, and practicable, if the following changes are made:

- Revise the repair criteria for corrosion metal loss affecting a long seam in HCAs and non-HCAs as follows:
  - Insert the word ‘preferentially’ to assure that this criterion would not be applied to corrosion pits near a long seam. It would apply to corrosion along the seam that could lead to slotting-type, crack-like defects.

- Delete the following repair criteria (HCAs and non-HCAs):
  - Gouge or groove > 12.5% wall thickness
  - Area of corrosion > 50%

Approved GPAC Language 3/28/18

- Revise proposed § 192.485(c) to include reference to §192.712 for evaluating corrosion in proximity to cracks or crack-like defects and for operators to make and retain records.

BEFORE THE
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
WASHINGTON, D.C.

Pipeline Safety: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change and Other Related Amendments	Docket Nos. PHMSA-2016-0136, PHMSA-2011-0023

COMMENTS ON PIPELINE SAFETY: REPAIR CRITERIA, INTEGRITY MANAGEMENT IMPROVEMENTS, CATHODIC PROTECTION, MANAGEMENT OF CHANGE, AND OTHER RELATED AMENDMENTS FINAL RULE

FILED BY
AMERICAN GAS ASSOCIATION
AMERICAN PETROLEUM INSTITUTE
AMERICAN PUBLIC GAS ASSOCIATION
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

June 6, 2018

language reflects the appropriate amount of specificity for the requirement to consider tool tolerance. Exact considerations and processes for addressing tool tolerance may vary by tool and anomaly calculation methodology, based on an operator's overall integrity program.

(3) PHMSA should make specific modifications to align the anomaly response criteria with consensus technical standards and current technologies.

In Section III of these comments, the Associations recommend specific modifications to PHMSA's proposed regulatory text to align the anomaly response criteria with the GPAC's discussion. The Associations offer further detail around the following topics:

A. *PHMSA should include a new § 192.714 to describe the engineering critical assessment requirements for dents with indication of metal loss, cracking or a stress riser.*

The Associations strongly support PHMSA's proposal to add an engineering critical assessment methodology for dents with indication of metal loss, cracking or a stress riser.[16] As noted by PHMSA, "the original repair criteria for dents were developed in the early 2000s timeframe for both HL and gas integrity management rules. Both ILI technology and analytical techniques to assess dents have advanced significantly since that time. PHMSA has gained confidence in applying ECA techniques to analyze dent defects through recent application of dent ECA in special permits."[17]

The Associations suggest that PHMSA include a new § 192.714 to describe the engineering critical assessment requirements for dents with indication of metal loss, cracking or a stress riser. In Section III of these comments, the Associations recommend language for § 192.714 based on PHMSA's slide presentation during the GPAC meeting and the proceeding discussion and votes. The Associations believe § 192.714 should only apply to dents with indication of metal loss, cracking or a stress riser, as considerations for these dents are different than for plain dents. Engineering analysis requirements for plain dents based on critical strain are already established in Part 192.

B. *For crack or crack-like defects, 1.1 times MAOP is an appropriate threshold for "immediate" anomalies.*

For crack or crack-like defects, the GPAC directed PHMSA to consider a 1.1 x MAOP threshold for immediate conditions, "after tool tolerance has been field verified and applied."[18] As discussed above, PHMSA's proposed language already includes requirements for explicitly considering and verifying tool tolerance. Using 1.1 x MAOP as the immediate threshold for crack anomalies appropriately balances the need for a conservative criterion with the need to minimize the customer and community disruptions associated with immediate conditions. 1.1 x MAOP is consistent with the existing threshold for immediate corrosion anomalies in § 192.933(d)(1)(i) and API RP 1176: *Recommended Practice for Assessment and Management of Cracking in Pipelines*.

Per Member Drake, "I just want to follow up on one point, and I want to be clear on this. I'm talking about an either/or here with the 1.1 and tool tolerances. I'm not talking about adding tool tolerances,

[16] GPAC Meeting Final Voting Slides. March 26-28, 2018. Slide 20.
[17] PHMSA. "GPAC-Slide_Presentation_-Gas_Rule_-_March_26_to_28_Mtg_5_-_FINAL." March 26-28, 2018. Slide 147.
[18] GPAC Meeting Final Voting Slides. March 26-28, 2018. Slide 22.

Finally, in reviewing internal/external corrosion incidents reported to PHMSA since 2010, the Associations identified that more than 70% of these incidents occurred on segments that had NOT been assessed with ILI for metal loss anomalies. The ASME B31.8S (2004) Section 7, Figure 4 requirements apply primarily to lines that have had ILI. The fact that most corrosion incidents have occurred on pipelines that have not be inspected with an ILI tool indicates that following the current industry practice to remediate corrosion anomalies identified through ILI based on ASME B31.8S (2004) Section 7, Figure 4 is an effective practice.

D. PHMSA should ensure operators can use the reciprocal of the pipe design factor as an alternative to class-based factors for grading anomalies.

Wherever PHMSA applies class location-based safety factors (e.g., 1.39 x MAOP for scheduled metal loss anomalies in class 3 and 4 areas), it is critical that the code language allow for an alternate factor **equal to** "the reciprocal of the design factor of the installed pipe." This will accommodate segments that are being managed in compliance with the alternate MAOP (§ 192.620) and class location change (§ 192.611) regulations. As noted by Mr. Johnson with Energy Transfer during the GPAC meeting, "[I]f you apply the reciprocals of those, strictly as the Class Location Factors to any of these pipes, say, a pipe that was designed with 0.72 design factor that's operating that way in a Class 2 area, if you apply the Class 2 factor to it, the pipe itself will not pass, ***regardless of whether it has a defect in it***."[23] Similarly, as noted by Mr. Nanney with PHMSA, "When you say Class 1 pipe or whether you say Class 2 or 3, that means you've got a design factor based upon that class and that also means that you would have pipe diameter wall thickness grade attributes based upon that. From Class 1 to Class 2, the reason the question was asked and we added the comment in red was because if you have a class change from 1 to 2, you've had a pressure test in the past at a certain amount to be able to do that. And so that design factor would not change if it was a 0.72, which is, 1.39 is the reciprocal 0.72, and they're both interchanged depending upon how you're using them. That pipe wouldn't change. That same wall thickness and grade would be still there, so that's why we clarified that. We thought it was clarified in the notice, and we'll make sure we clarify it."[24]

When developing code language to allow for consideration of pipe design factor, PHMSA must consider that a pipeline without any anomalies may have a predicted failure pressure **equal to** the reciprocal of the design factor of the installed pipe. The Associations have recommended language in Section III below to allow for consideration of pipe design factor when grading anomalies.

E. Metal-loss affecting a longitudinal seam should be removed from the response criteria if the seam was formed by high-frequency electric resistance welding (HF-ERW).

The Associations identified zero incidents related to corrosion or environmental corrosion cracking ("metal loss") affecting the long seam of HF-ERW pipe from 2010 – 2017. It is well-established that HF-ERW pipe is not susceptible to threats like some pre-1970s LF-ERW seam types.[25] Therefore, PHMSA should remove metal-loss affecting a longitudinal seam from the response criteria if the seam was formed by high-frequency electric resistance welding (HF-ERW).

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[23] GPAC Meeting Transcript. March 28, 2018. Page 67-68.
[24] GPAC Meeting Transcript. March 28, 2018. Page 79-80.
[25] E.B. Clark, B.N. Leis, R.J. Eiber, *Integrity Characteristics of Vintage Pipelines*, Battelle Memorial Institute, October 2004, Columbus, Ohio

§192.714 Engineering Critical Assessment for dents with an indication of metal loss or a stress riser

(a) ***Applicability*. Where allowed by this part, if an operator elects to use engineering critical assessment to evaluate a dent anomaly with an indication of metal loss or a stress riser, the operator must use the process described in this section. This process does not apply to dents with coincident cracking, as identified through inline or visual inspection. Dents with coincident cracking must be remediated in accordance with § 192.713 or § 192.933, as applicable.**

(b) ***Engineering Critical Assessment*. An engineering critical assessment is an analytical procedure through which an operator demonstrates that a dent anomaly with an indication of metal loss or a stress riser does not jeopardize pipeline integrity. The engineering critical assessment must:**

(1) **Evaluate potential threats to the pipe segment in the vicinity of the dent, including movement, loading and corrosion;**

(2) **Identify and quantify all loads acting on the dent;**

(3) **Review inline inspection data for damage in the dent area and any associated weld region;**

(4) **Perform pipeline curvature-based strain analysis, using inspection data from recent inline inspection with a high resolution deformation tool**

(5) **Compare dent profile between recent and previous inline inspections to identify any significant changes in dent depth and shape, if multiple inline inspections with a high resolution deformation tool have been conducted; and**

(6) **Evaluate geometric strain level associated with the dent and any associated welds using a technically appropriate methodology ~~using Finite Element Analysis (FEA)~~ and calculate the plastic strain limit damage factors or other technically appropriate damage factors to infer the possibility of a crack. Dents with geometric**

> Per PHMSA Presentation Slide 147-149 from the March 26-28, 2018 GPAC meeting:
> "PHMSA: Summary of suggested ECA for Denting:
> - Evaluate potential threats for the pipe segment in the vicinity of the dent including movement, loading, and cathodic protection;
> - Review HR-MFL and HR-Deformation inline inspection data for damage in the dent area and any associated weld region;
> - Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data;
> - Compare dent profile between the recent and past HR-Deformation inspections to identify significant changes in dent depth and shape;
> - Identify and quantify all loads acting on the dent for a basis for ECA;
> - Evaluate strain level associated with dent and any welds using Finite Element Analysis (FEA), and calculate the plastic strain limit damage factors to infer the possibility of a crack;
> - Estimate the fatigue life of the dent using FEA with the operational pressure data and different fatigue life prediction models, which must have reassessment safety factor of 2."

> Per Mr. Nanney with PHMSA (3/28/18 GPAC Meeting Transcript, page 52): "Just to reply to the comment we got on denting, the answer there would be yes, we agree with the gentleman from TransCanada's comment that Finite Element Analysis would not be required on all dents."

strain levels that exceed 12% or that exceed the critical strain must be remediated in accordance with § 192.713 or § 192.933, as applicable. The analysis must account for material property uncertainties and model inaccuracies and tolerances.

(c) ***Analysis for Remaining Life.*** **If the operator determines that the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue, fatigue analysis must be performed using a technically appropriate engineering methodology. The analysis must account for model inaccuracies and tolerances. The operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.**

(d) ***Review.*** **Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.**

(e) ***Records*****. Each operator must keep for the life of the pipeline records of the analyses made in accordance with the requirements of this section after** ***[insert effective date of the rule].***

Subpart O – Gas Transmission Pipeline Integrity Management

§192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework (*see* §192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) for more detailed information on the listed element.)

(a) An identification of all high consequence areas, in accordance with §192.905.
(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.
(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment.
(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§192.925, 192.927, or 192.929.
(e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment.
(f) A process for continual evaluation and assessment meeting the requirements of §192.937.
(g) If applicable, a plan for confirmatory direct assessment meeting the requirements of §192.931.
(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.
(i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of §192.945.
(j) Record keeping provisions meeting the requirements of §192.947.
(k) A management of change process as required by §192.13(d).
(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.
(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by—
    (1) OPS; and
    (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
(n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to—
    (1) OPS; and
    (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
(o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.
(p) A process for identification and assessment of newly-identified high consequence areas. (*See* §192.905 and §192.921.)

§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as manufacturing, welding/fabrication or equipment defects;

(3) Time independent threats such as third party damage/mechanical damage, incorrect operational procedure, weather related and outside force damage; including consideration of seismicity, geology, and soil stability of the area; and

(4) Human error such as operational mishaps and design and construction mistakes.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather~~, verify, validate,~~ and integrate **pertinent** existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. **Operators must begin to integrate pertinent data elements specified in this section starting [*insert date 1 year after effective date of the final rule*], with pertinent attributes integrated by [*insert date 3 years after publication of rule.*]** At a minimum, an operator must gather and evaluate the set of data specified in paragraph (b)(1) of this section and Appendix A to ASME/ANSI B31.8S. The evaluation must analyze both the covered segment and similar non-covered segments, and must:

(1) Integrate **pertinent** information about pipeline attributes and other relevant information, including, but not limited to:

(i) Pipe diameter, wall thickness, grade, seam type and joint factor;

Mr. Nanney stated, "on 917(b) we had heard the committee want us to, in the actual wording, to take out, 'verify' and 'validate', and put in, 'gather' and 'integrate.'" (6/6/2017 Transcript. Page 329. Line 5)

Per the June 7, 2017 GPAC Meeting Vote (Slide 57, Bullet #1, Part 2). PHMSA will add language to require data that is "pertinent" (and that a prudent operator would collect)." The Associations agree that operators should be expected to collect pertinent data in a prudent manner. However, the Associations are concerned that this "prudent operator" standard is undefined, and it would be very complicated to enforce; the Associations do not believe that this term is appropriate for regulatory text. Instead, PHMSA should reference the GPAC's discussion around pertinent data that "a prudent operator would collect" in its preamble to the Final Rule.

Per the June 6-7 GPAC Vote (Slide 57, Bullet #2). PHMSA will include an "implementation timeframe beginning in year 1 with full incorporation by 3 years."

National Energy Board

Office national de l'énergie

File OF-Surv-Gen 11 01
3 July 2019

To: All companies under National Energy Board Jurisdiction
Canadian Energy Pipeline Association
Canadian Association of Petroleum Producers
Provincial and Territorial Regulators

National Energy Board Safety Advisory
NEB SA 2019-01
Potential for Low Toughness and Lack of Fusion of Weld Zone in Hyundai API 5L Electric Resistance Weld (Hyundai API 5L ERW) Pipe

Please find attached Safety Advisory SA 2019-01.

The National Energy Board (NEB or the Board) expects regulated companies to demonstrate a proactive commitment to continual improvement in safety, security and environmental protection, and to promote a positive safety culture as part of their management systems.

Safety Advisories are issued periodically in order to improve the oil and gas industry's awareness of an identified safety or environmental concern with the goal of preventing incidents from occurring. A Safety Advisory also serves to further highlight NEB requirements, and conveys the Board's expectation that regulated companies take appropriate action to mitigate any potential impacts to people or the environment.

If you have any questions regarding this advisory please contact the Director of Research and Innovation at the Board through our toll free number at 1-800-899-1265.

Yours truly,

Original signed by L. George for

Sheri Young
Secretary of the Board

Attachment

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Potential for Low Toughness and Lack of Fusion of Weld Zone in Hyundai API 5L Electric Resistance Weld Pipe

Background

The National Energy Board (NEB or the Board) is aware of instances in the United States where Hyundai API 5L Electric Resistance Weld (Hyundai API 5L ERW) pipe manufactured in 2014 and 2015 by Hyundai Steel Company (Hyundai) in Ulsan, South Korea, failed during pre-service field hydrostatic testing (hydrotest).

In one instance, an operator experienced an issue with Hyundai API 5L ERW pipe that demonstrated both lack of fusion (LOF)[1] and low toughness properties at the weld zone that were below the required specifications. The subject pipe failed during field hydrotest in 2017. The fracture was initiated at a LOF defect and propagated along the longitudinal seam for the entire length of the pipe joint due to low toughness. The line pipe was API Monogram[2] 5L HFN ERW PSL2 manufactured by Hyundai in Ulsan, South Korea, and purchased from a distributor in the United States.

The operator proceeded to test other Hyundai API 5L ERW line pipe purchased from distributors for their current projects and found other pipe joints that had insufficient Charpy V Notch (CVN) toughness values. API 5L specifies 27 J @ 0 °C (20 ft-lbs @ 32 °F) as the minimum required toughness value for longitudinal seam, however some tested pipe exhibited single digit CVN values. The operator replaced suspect Hyundai line pipe in several dozen stations and several kilometers of pipeline.

From July 2018 until April 2019 the NEB and United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) held a number of meetings with Hyundai and Hyundai Canada Inc. During the meetings, the NEB asked a number of questions of Hyundai. Hyundai and Hyundai Canada Inc. have been responsive to all questions raised. Hyundai has provided information to the NEB concerning root cause and corrective action. Hyundai also outlined the implementation of corrective actions it is taking. The NEB has considered all of Hyundai's submissions and filings.

[1] The term lack of fusion means incomplete fusion as used in CSA Z662-19.

[2] API Monogram is a voluntary licensing program that facilitates the consistent manufacturing of product that conforms to applicable API Specifications. Licensed manufacturers are given the authority to apply the API Monogram registered mark to equipment that meets the requirements.

Cover page

In connection with the rulemaking process of "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments" (RIN 2137-AF39), PHMSA considered certain operator submitted information for the use of "other technology" under 49 CFR 192.921(a)(4), 192.937(c)(4), and 192.949(a).

Non-confidential information submitted to PHMSA includes the following.

Kinder Morgan

Technical Justification for use of EMAT as an Alternative Technology for Integrity Assessment of SCC in HCAs

September 2019

4 Continuous Improvement

This proposal is based on the current state of the art of EMAT technology, available assessment methods, and currently available data. Limitations of the technology have been identified and measures have been proposed in this document to address or accommodate those limitations. This proposal comprises a prudent, conservative means to utilize EMAT ILI technology as a means to manage SCC. However, KM continues to collaborate with the EMAT service provider to improve the technology and plans on leveraging the efforts to continuously improve the use of the technology. This section provides a brief overview of some of the major initiatives that are presently underway.

4.1 Refined EMAT Length Measurement

Kinder Morgan and the EMAT service provider are currently evaluating the accuracy of a more refined length measurement. As the technology is continuously improving, when the data supports the use of more accurate and less conservative estimates of the effective crack length, KM may choose to employ a less restrictive methodology. In addition to colony length the ILI vendor also provides an interlinking crack length measurement taken one millimeter below the pipe surface. To date 25 samples have been validated that meet the detection specification and have this additional length measurement as shown in Figure 7. The results currently indicate better agreement; however, KM will continue to collect additional data points until a larger sample set can be statistically analyzed.

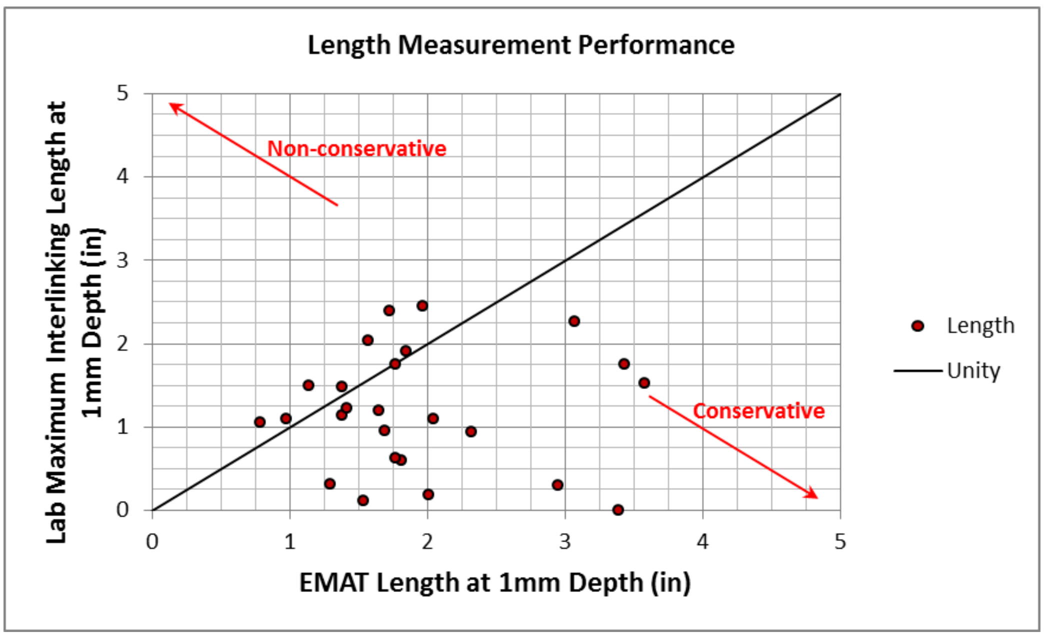

Figure 7 Length at 1mm Depth

4.2 X-ray Computed Tomography

X-ray computed tomography (CT) makes use of computer-processed combinations of multiple X-ray images taken from different angles to produce cross-sectional images of a scanned object, allowing the user to see inside the object without cutting. The technology has been widely used for imaging in the medical industry and in recent years has seen adoption by other industries as well. While the technology

has seen increased use by the aviation and automobile industry, the technology has not been used extensively by the pipeline industry.

KM understands that there is a need for highly accurate and detailed validation measurements to be provided to the EMAT ILI vendor. Recognizing that existing in-ditch non-destructive testing technologies have inherent limitations, KM has relied heavily on X-ray CT coupons removed from the pipe. KM is the first company to size SCC colonies using X-ray CT. Recent advances in technology have enabled X-ray CT to provide sufficient resolution while penetrating through four inches of steel. This allows individual cracks within SCC to be seen and measured.

The measurements obtained from X-ray CT have been validated by metallurgical sectioning and show excellent agreement. This eliminates the need for considering in-ditch error and therefore provides much better validation with almost no uncertainty with regards to validation. Furthermore, the high level of detail and accuracy in XCT data enables KM and the ILI vendor to further improve EMAT technology and processes. This technology is not yet miniaturized and ruggedized for field use; as such, future projects continue to use X-ray CT sizing.

Locations were identified within samples for validation using metallurgical sectioning. Figure 8 shows a comparison of the X-ray CT data with the corresponding crack profile as obtained by metallurgical sectioning. As can be seen, there is exceptional agreement between the measurements.

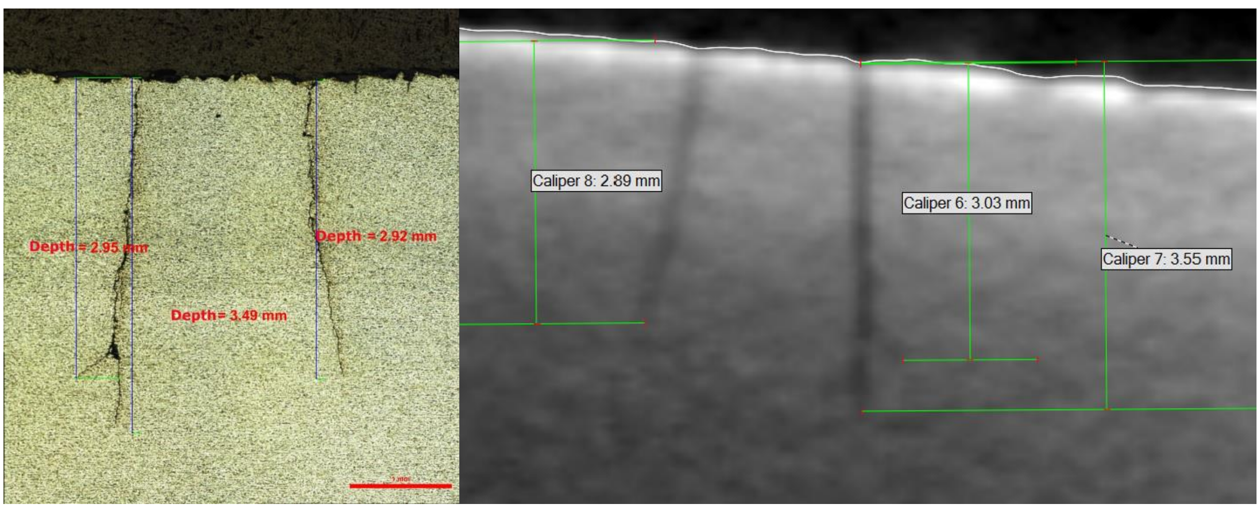

Figure 8 Cross Section Comparison a) Micrograph; b) X-ray CT

KM has been working with the EMAT ILI vendor to incorporate the use of this information into the development and improvement of the EMAT technology and the analysis process. X-ray CT will provide detailed maps of individual cracks in a 3D model such that a colony can be virtually cross sectioned at any point. Through the use of additional tools the depth profile of each crack can be output such that the vendor will know the exact location, depth and position of almost every crack in an SCC colony.

4.2.1 Improvement of In-field Measurements

KM, individually and in conjunction with the Pipeline Research Council International (PRCI), continues to work with technology and inspection vendors to develop and validate in-field sizing techniques. This has been enabled through the examination of X-ray CT samples and provision of unprecedented accurate and detailed data. KM intends to continue exploring the use of actual SCC colonies as calibration or validation samples to increase the reliability of in-field measurements.

A benefit of X-ray CT is that the samples remain intact and are not destructively sized. This is important, because to date, there are no calibration samples for the sizing of SCC in the field using actual cracks. When calibrating ultrasonic tools, inspectors are limited to manufactured reference standards. These provide a good benchmark but are an idealized reflecting surface and may not always be the ideal substitute for crack faces. Creating samples from similar pipe with similar defects that have absolute measurements may be an important step in the confirmation of colony sizes and hence the correlation to EMAT performance.

4.2.2 Incremental Validation

KM, with the ILI service provider, will continue to validate future tool runs through new digs or the use of existing dig data that is closely related. KM will continue to use qualified field inspectors, advanced in-ditch measurement techniques, and in-ditch, X-ray CT, or metallurgical lab results to ensure that EMAT is validated in accordance with API 1163 In-line Inspection Systems Qualification.

Pipe Seam Failures – Electric Resistance Welding (ERW)

Jan. 1, 2010 to Dec. 31, 2020

ERW Pipe Seam - High Frequency
Gas Transmissions Incidents Caused by Material Failure of Pipe or Weld
2010 - 2020

DATE	REPORT ID	STATE	ITEM INVOLVED	OD[i] (in)	WT[ii] (in)	SMYS[iii] (psi)	MAOP[iv] (psig)	MANUFACTURER	MANUFACTURE YEAR	INSTALL YEAR
3/2/2010	20100006	KS	GIRTH WELD/FUSION, HAZ	26	0.281	60,000	900	NATIONAL TUBE DIV., U.S. STEEL CORP	1967	1968
1/15/2011	20120050	KS	PIPE BODY - Crack in pipe on rock	10	0.188	46,000	1,100	STUPP ERW	1964	1964
5/24/2011	20110184	ID	PIPE BODY - Dent and Crack	24	0.25	60,000	850	AMERICAN PIPE	1992	1992
6/6/2012	20120066	TX	PIPE BODY - Hard Spot Cracks	26	0.25	52,000	720	A.O. SMITH	1957	1957
8/2/2012	20120087	TN	PIPE BODY - Construction Dents	12	0.25	42,000	735	UNKNOWN	1982	1982
8/9/2013	20130081	LA	PIPE BODY - Pipe Seam	12	0.219	52,000	1,000	AMERICAN STEEL	1984	1984
10/29/2013	20130108	KS	PIPE BODY - Crack in Pipe and Girth Weld	26	0.344	60,000	900	KAISER	1967	1968
4/10/2014	20140049	TX	PIPE SEAM and Girth Weld	20	0.25	56,000	953	AMERICAN STEEL PIPE	1967	1967
2/3/2015	20150042	AK	GIRTH WELD/FUSION, HAZ	16	0.312	46,000	1,050	KAISER	1974	1974
10/21/2017	20170107	OK	PIPE BODY - Bending Overload and Girth Weld Offset (high/low)	20	0.257	65,000	1,200	STUPP	1980	1980
10/21/2017	20170109	WV	PIPE BODY - Bending Overload	6	0.219	35,000	1,050	BETHLEHEM STEEL	UNKNOWN	1977
11/20/2017	20170124	MI	PIPE BODY - Bending Overload and Girth Weld Offset (high/low)	22	0.281	52,000	790	YOUNGSTOWN STEEL	1951	1951
1/8/2020	20200008	OK	PIPE SEAM	16	0.25	65,000	1,216	PARAGON	2014	2014

ERW Pipe Seam - Unknown Frequency
Gas Transmissions Incidents Caused by Material Failure of Pipe or Weld
2010 - 2020

DATE	REPORT ID	STATE	ITEM INVOLVED	OD (in)	WT (in)	SMYS (psi)	MAOP (psig)	MANUFACTURER	MANUFACTURE YEAR	INSTALL YEAR
6/29/2010	20100046	CO	PIPE BODY - SCC[v]	4	0.188	35,000	691	UNKNOWN	1965	1965
9/1/2010	20100062	LA	PIPE SEAM - Lack of fusion	10	0.25	46,000	1,076	LONESTAR	1959	1959
12/2/2010	20100110	CO	PIPE BODY - SCC	20	0.312	41,000	920	YOUNGSTOWN STEEL	1947	1947
2/7/2012	20120025	IN	PIPE SEAM - Lack of fusion	22	0.281	52,000	858	UNKNOWN	1956	1956
6/13/2013	20130064	WY	PIPE BODY - SCC	12	0.219	42,000	865	REPUBLIC STEEL	1963	1963
1/10/2015	20150013	LA	PIPE BODY	20	0.469	52,000	1,273	U.S. STEEL	1972	1974
6/5/2016	20160056	CA	PIPE BODY - SCC	12	0.219	52,000	890	U.S. STEEL	UNKNOWN	1972
2/28/2017	20170028	CA	PIPE BODY - SCC	8	0.172	42,000	720	UNKNOWN	1972	1972
5/5/2017	20170041	CO	PIPE SEAM - Lack of fusion	16	0.203	56,000	1,000	YOUNGSTOWN STEEL	1967	1967
1/18/2019	20190014	TX	PIPE BODY	4	0.237	24,000	250	UNKNOWN	1953	1953
7/26/2019	20190098	OK	PIPE BODY - SCC	20	0.25	52,000	780	U.S. STEEL	1970	1970
4/9/2020	20200047	TX	PIPE SEAM	20	0.25	46,000	612	YOUNGSTOWN STEEL	UNKNOWN	1949
9/2/2020	20200101	LA	PIPE SEAM	4	0.237	24,000	1,100	UNKNOWN	1951	1951
11/7/2020	20200122	MI	GIRTH WELD/FUSION, HAZ[vi]	16	0.203	60,000	945	YOUNGSTOWN STEEL	UNKNOWN	1965

ERW Pipe Seam - Low Frequency
Gas Transmissions Incidents Caused by Material Failure of Pipe or Weld
2010 - 2020

DATE	REPORT ID	STATE	ITEM INVOLVED	OD (in)	WT (in)	SMYS (psi)	MAOP (psig)	MANUFACTURER	MANUFACTURE YEAR	INSTALL YEAR
3/1/2010	20100008	AZ	PIPE BODY - Crack	30	0.438	52,000	845	A.O. SMITH	1969	1969
9/24/2010	20100079	TN	PIPE SEAM - Lack of Fusion	12	0.25	42,000	823	REPUBLIC	1950	1950
9/25/2010	20100078	TN	PIPE SEAM - Lack of Fusion	12	0.25	42,000	823	REPUBLIC	1950	1950
10/14/2010	20100090	MS	PIPE SEAM	20	0.25	46,000	550	YOUNGSTOWN STEEL	1949	1949
10/19/2010	20100082	LA	PIPE SEAM - Lack of Fusion	20	0.312	52,000	1,170	YOUNGSTOWN STEEL	1958	1959
1/24/2011	20110021	MS	PIPE BODY – Leak due to filet weld	24	0.375	52,000	975	REPUBLIC	1957	1959
5/26/2011	20110202	TX	PIPE SEAM - Hook crack	20	0.25	46,000	575	YOUNGSTOWN STEEL	1949	1950
12/26/2012	20130007	FL	PIPE SEAM - Hook crack/ hardspot	20	0.25	52,000	936	YOUNGSTOWN STEEL	1959	1959
4/23/2013	20130040	WI	GIRTH WELD/FUSION, HAZ	8	0.156	42,000	895	LONE STAR	1965	1966
11/7/2013	20130111	LA	PIPE SEAM - Lack of Fusion	12	0.281	42,000	1,233	REPUBLIC	1954	1954
11/15/2013	20130114	LA	PIPE SEAM	12	0.281	42,000	1,233	REPUBLIC	1954	1954
3/25/2014	20150027	OFFSHORE - TX	PIPE SEAM	12	0.375	42,000	525	N/A	1951	1951
5/17/2014	20140066	FL	PIPE SEAM	8	0.203	52,000	975	LONESTAR	1962	1962
8/3/2015	20150110	TX	PIPE BODY - SCC	16	0.25	42,000	903	YOUNGSTOWN STEEL	1947	1947
3/20/2017	20170078	MI	GIRTH WELD/FUSION, HAZ	16	0.203	60,000	945	YOUNGSTOWN STEEL	1965	1965
11/8/2018	20180126	LA	GIRTH WELD/FUSION, HAZ	12	0.25	42,000	1,050	LONESTAR	UNKNOWN	1956
1/20/2019	20190016	NE	PIPE BODY	6	0.25	24,000	500	UNKNOWN	1931	1932
4/3/2019	20190055	CA	GIRTH WELD/FUSION, HAZ	6	0.188	30,000	150	UNKNOWN	UNKNOWN	1962
10/23/2019	20190120	PA	PIPE SEAM	16	0.25	52,000	780	YOUNGSTOWN STEEL	1964	1964
11/1/2019	20190121	PA	PIPE SEAM	16	0.25	52,000	780	YOUNGSTOWN STEEL	1964	1964
11/8/2019	20190127	NC	PIPE SEAM - Crack girth weld offset high-low	42	0.625	60,200	780	NA	UNKNOWN	2017
2/18/2020	20200023	TX	PIPE SEAM - Lack of Fusion	8	0.188	46,000	795	YOUNGSTOWN STEEL	1950	1950
9/10/2020	20200105	FL	PIPE BODY - SCC	12	0.219	42,000	713	YOUNGSTOWN STEEL	1959	1959
9/24/2020	20200112	FL	PIPE BODY - SCC	18	0.25	52,000	866	YOUNGSTOWN STEEL	UNKNOWN	1959

* All data based on PHMSA incident report data. PHMSA incident report data relies on operator-provided information on incident reports.
[i] Outside diameter (OD)
[ii] Wall thickness (WT)
[iii] Specified minimum yield strength (SMYS)
[iv] Maximum allowable operating pressure (MAOP)
[v] Stress corrosion cracking (SCC)
[vi] Heat affected zone (HAZ)

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket No. PHMSA–2011–0023; Amdt. No. 192–132]

RIN 2137–AF39

Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: PHMSA is revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas transmission pipelines. This final rule addresses several lessons learned following the Pacific Gas and Electric Company incident that occurred in San Bruno, CA, on September 9, 2010, and responds to public input received as part of the rulemaking process. The amendments in this final rule clarify certain integrity management provisions, codify a management of change process, update and bolster gas transmission pipeline corrosion control requirements, require operators to inspect pipelines following extreme weather events, strengthen integrity management assessment requirements, adjust the repair criteria for high-consequence areas, create new repair criteria for non-high consequence areas, and revise or create specific definitions related to the above amendments.

DATES: The final rule is effective May 24, 2023. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of May 24, 2023. The incorporation by reference of other publications listed in this rule was approved by the Director of the Federal Register on July 1, 2020.

FOR FURTHER INFORMATION CONTACT: Technical questions: Steve Nanney, Senior Technical Advisor, by telephone at 713–272–2855. General information: Robert Jagger, Senior Transportation Specialist, by telephone at 202–366–4361.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of the Regulatory Action

This final rule concludes a decade-long effort by PHMSA to amend its regulations governing onshore natural gas transmission pipelines in response to the tragic September 9, 2010, incident at a Pacific Gas and Electric Company (PG&E) gas transmission pipeline in San Bruno, CA, which resulted in the death of 8 people, injuries to more than 60 other people, and the destruction or damage of over 100 homes. PHMSA expects the new requirements in this final rule will reduce the frequency and consequences of failures and incidents from onshore natural gas transmission pipelines through earlier detection of threats to pipeline integrity, including those from corrosion or following extreme weather events. The safety enhancements in this final rule, therefore, are expected to improve public safety, reduce threats to the environment (including, but not limited to, reduction of greenhouse gas emissions released during natural gas pipeline incidents), and promote environmental justice for minority populations, low-income populations, and other underserved and disadvantaged communities that are located near interstate gas transmission pipelines.

Although the Federal Pipeline Safety Regulations (49 Code of Federal Regulations (CFR) parts 190 through 199; PSR) applicable to gas transmission and gathering pipeline systems set forth in parts 191 and 192 have increased the level of safety associated with the transportation of gas, serious safety incidents continue to occur on gas transmission and gathering pipeline systems, resulting in serious risks to life and property. In its investigation of the 2010 PG&E incident, the National Transportation Safety Board (NTSB) found among several causal factors that PG&E had an inadequate integrity management (IM) program that failed to detect and repair or remove a defective pipe section on its gas transmission line.[1] PG&E based its IM program on incomplete and inaccurate pipeline information, which led to, among other issues, faulty risk assessments, improper assessment method selections, and internal assessments of the program that were superficial and resulted in no meaningful improvement.[2]

Prior to the PG&E incident, PHMSA had initiated an advance notice of proposed rulemaking (ANPRM) to seek comment on whether the IM requirements in part 192 should be changed and whether other issues related to pipeline system integrity should be addressed by strengthening or expanding non-IM requirements.

[1] NTSB, NTSB/PAR–11–01, ''Pipeline Accident Report: Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010'' (2011) (NTSB Incident Report on San Bruno).

[2] NTSB Incident Report on San Bruno at 107–115.

PHMSA published the ANPRM on August 25, 2011.[3]

Based on the comments on the ANPRM, PHMSA published a notice of proposed rulemaking (NPRM) on April 8, 2016, to seek public comments on proposed changes to the PSR governing transmission and gathering lines.[4] A summary of those proposed changes pertaining to this rulemaking, corresponding stakeholder feedback, and PHMSA's responses to stakeholder feedback on the individual provisions, is provided below in section III of this document (Discussion of NPRM Comments, GPAC Recommendations, and PHMSA Response).

PHMSA determined that the most efficient way to manage the proposals in the NPRM was to divide them into three separate final rule actions. The first of these final rules was published on October 1, 2019, and addressed topics primarily relating to congressional mandates and safety recommendations, including maximum allowable operating pressure (MAOP) reconfirmation and material properties verification, the expansion of integrity assessments beyond high-consequence areas (HCA), the consideration of seismicity, in-line inspection (ILI) launcher and receiver safety, MAOP exceedance reporting, and strengthened requirements for assessment methods (2019 Gas Transmission Rule).[5] Provisions related to gas gathering pipelines were addressed in a separate rulemaking.[6] This rulemaking finalizes the remaining provisions from the NPRM as outlined below.

B. Summary of the Major Provisions of the Final Rule

To reduce the risks of pipeline incidents, PHMSA is amending the PSR applicable to gas transmission pipelines to improve the protection of the public, property, and the environment; close regulatory gaps; and adopt additional safety measures to improve safety inside and outside of HCAs. Specifically, PHMSA is making changes to clarify the IM requirements; improve the management of change (MOC) process; strengthen corrosion control requirements; provide parameters for inspections following extreme weather events; strengthen requirements related to the IM assessment methods; and improve the repair criteria for pipeline anomalies. PHMSA is also amending certain definitions in part 192 in support of these provisions.

PHMSA is modifying the IM regulations by adding specificity to the data integration language. The final rule establishes several pipeline attributes that must be included in an operator's risk analysis when an operator determines what threats are applicable to a pipeline segment. PHMSA is also explicitly requiring that operators integrate analyzed information into their IM programs and is requiring that data be verified and validated. Additionally, PHMSA is issuing requirements for applying knowledge gained through an operator's IM program, including provisions for analyzing interacting threats, potential failures, and worst-case incident scenarios from the initial failure to incident termination. Several of these items were proposed in response to NTSB findings following the PG&E incident that suggested pipeline operators were often not conducting data analysis, data integration, threat identification, and risk assessment in the manner originally intended and specified in subpart O of part 192.

Similarly, following the PG&E incident, PHMSA, informed by (inter alia) the NTSB's evaluation of the incident and ANPRM comments, determined that the existing MOC requirements and industry practices were not sufficient[7] and looked to align the regulatory requirements with the standards outlined in American Society of Mechanical Engineers/American National Standards Institute (ASME/ANSI) B31.8S.[8] Specifically, this final rule requires each operator of an onshore gas transmission pipeline to develop and follow a MOC process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary.

This final rule also improves and updates the corrosion control requirements for gas transmission pipeline operators. Based on lessons PHMSA has learned following several pipeline failures, and following PHMSA's workshop on pipeline construction in Fort Worth, TX, on April 23, 2009,[9] PHMSA determined that construction practices, including the installation of pipe in-ditch, can result in damaged coating that can compromise corrosion control. Therefore, this rule requires that operators perform assessments to identify suspected damage promptly after backfilling and then remediate any coating damage found. Further, PHMSA has noted that the existing regulations were not always effective at eliminating deficiencies in cathodic protection[10] corrosion control or at preventing incidents from internal corrosion. Therefore, this rule strengthens the requirements for internal and external corrosion controls related to monitoring requirements and surveys. PHMSA also determined that additional prescriptive preventive and mitigative (P&M) measures are needed for managing electrical interference currents.

Extreme weather has been a contributing factor in several pipeline failures. PHMSA issued Advisory Bulletins in 2015, 2016, and 2019 to communicate the potential for damage to pipeline facilities caused by severe flooding, including actions that operators should consider taking to ensure the integrity of pipelines in the event of flooding, river scour, river channel migration, and earth movement.[11] As PHMSA has noted in another series of Advisory Bulletins, hurricanes are also capable of causing extensive damage to both offshore and inland pipelines.[12]

[3] "Safety of Gas Transmission Pipelines," 76 FR 53086 (Aug. 25, 2011).

[4] "Safety of Gas Transmission and Gathering Pipelines," 81 FR 20722 (Apr. 8, 2016).

[5] "Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," 84 FR 52180 (Oct. 1, 2019).

[6] "Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulations of Large, High-Pressure Lines, and Other Related Amendments," 86 FR 63266 (Nov. 15, 2021) (Gas Gathering Final Rule).

[7] See 81 FR 20796; NTSB Incident Report on San Bruno at 95–97 (concluding that the probable cause of the PG&E incident was PG&E's inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, and noting that PG&E had poor quality control during a pipe installation project that later failed in 2008 in Rancho Cordova, CA).

[8] ASME/ANSI "B31.8S–2004: Supplement to B31.8 on Managing System Integrity of Gas Pipelines" (Jan. 14, 2005).

[9] *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=58.*

[10] Cathodic protection is a technique used to control corrosion by making the metal pipe a cathode of an electrochemical cell. Essentially, the pipeline is connected to a more easily corroded metal that acts as an anode. That "sacrificial anode" metal corrodes instead of the metal that is being protected. For pipelines, passive galvanic cathodic protection is often not adequate, and an external direct current (DC) electrical power source is used to provide sufficient current.

[11] "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration," 80 FR 19114 (Apr. 9, 2015); "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration," 81 FR 2943 (Jan. 19, 2016); "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards," 84 FR 18919 (May 2, 2019).

[12] "Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricane Ivan," 69 FR 57135 (Sept. 23, 2004); "Pipeline Safety Advisory: Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricane Katrina," 70 FR 53272 (Sept. 7, 2005); "Pipeline Safety: Potential for

Continued

Because of the frequency and severe consequences of these events,[13] operators must protect the public from pipeline risks in the event of a natural disaster or extreme weather. While many prudent operators might voluntarily perform inspections following such events, the potential risk to public safety and environment merits codification of those practices in regulatory requirements. Therefore, PHMSA is amending the PSR to require that operators commence inspection of their potentially affected facilities within 72 hours after the operator determines the affected area can be safely accessed following the cessation of an extreme weather event such as a hurricane, landslide, flood; a natural disaster, such as an earthquake; or another similar event that has the likelihood to damage infrastructure. If an operator finds an adverse condition during the inspection, the operator must take appropriate remedial action to ensure the safe operation of the pipeline.[14]

PHMSA is also strengthening the standards for performing pipeline assessments by incorporating by reference certain consensus standards for both stress corrosion cracking (NACE International Standard Practice 0204–2008, ''Stress Corrosion Cracking Direct Assessment Methodology'' (2008) (NACE 0204–2008)) and internal corrosion direct assessments (NACE International Standard Practice 0206–2006, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas'' (2006) (NACE SP0206–2006)). Operators are already required to assess the condition of gas transmission pipelines in HCAs and certain non-HCAs periodically in accordance with §§ 192.710, 192.921, and 192.937. When the initial IM regulations creating subpart O were issued in 2003 (2003 IM rule), industry standards did not exist for these types of assessments.[15] By incorporating by reference the standards subsequently published by NACE International,[16] PHMSA is ensuring greater consistency, accuracy, and quality when operators perform these assessments.

This final rule also updates the existing repair criteria for HCAs by incorporating criteria for additional anomaly types such as crack anomalies, certain corrosion metal loss defects, and certain mechanical damage defects. Such revisions will provide greater assurance that operators will repair injurious anomalies and defects before those defects grow to a size that causes a leak or rupture. PHMSA also is finalizing explicit repair criteria for non-HCAs. Prior to this final rule, there were only general requirements in the regulations for operators to perform repairs in non-HCAs. The content of the non-HCA repair criteria being finalized in this rule is consistent with the criteria for HCAs; however, PHMSA has provided longer timeframes for the remediation of conditions that are not categorized as ''immediate'' conditions to provide operators the ability to prioritize remediating anomalous conditions in HCAs where consequences of a pipeline failure may be greater.

The various changes in this rule have also prompted additions and changes to certain definitions in part 192. PHMSA has created or made changes to the following terms: ''close interval survey,'' ''distribution center,'' ''dry gas or dry natural gas,'' ''hard spot,'' ''in-line inspection (ILI),'' ''in-line inspection tool or instrumented internal inspection device,'' ''transmission line,'' and ''wrinkle bend.''

C. Costs and Benefits

PHMSA has prepared an assessment of the benefits and costs of the final rule as well as reasonable alternatives. PHMSA estimates the annual costs of the rule to be approximately $17 million, calculated using a 7 percent discount rate. The costs reflect improvements made to the MOC process, additional corrosion control requirements, the provisions related to inspections following extreme weather events, and the changes made to the repair criteria. PHMSA finds that the other final rule requirements will not result in incremental costs.

PHMSA is posting the Regulatory Impact Analysis (RIA) for this rule in the public docket. PHMSA has determined that the regulatory amendments adopted in this final rule will improve public safety, reduce threats to the environment (including, but not limited to, reduction of methane emissions contributing to the climate crisis), and promote environmental justice for minority populations, low-income populations, and other underserved and disadvantaged communities. PHMSA finds the regulatory amendments adopted in this final rule are technically feasible, reasonable, cost-effective, and practicable because the public safety, environmental, and equity benefits of its regulatory amendments described herein and within its supporting documents (including the RIA and environmental assessment, each available in the docket for this rulemaking) will justify any associated costs and demonstrate and the superiority of the final rule compared to alternatives.

II. Background

A. Overview

On September 9, 2010, a 30-inch-diameter natural gas transmission pipeline, owned and operated by PG&E, ruptured in a residential neighborhood in San Bruno, CA. The rupture produced a crater approximately 72 feet long by 26 feet wide. The segment of pipe that ruptured weighed approximately 3,000 pounds, was 28 feet long, and was found 100 feet south of the crater. When the escaping gas ignited, the resulting fire killed 8 people, injured approximately 60 more, destroyed or damaged 108 homes, and caused the evacuation of over 300 people. In its pipeline accident report for the incident, the NTSB determined that the probable cause of the incident was PG&E's inadequate quality control and assurance when it relocated the line in 1956 and its inadequate IM program. The NTSB determined that PG&E's IM program was deficient and ineffective because it was based on incomplete and inaccurate pipeline information, did not consider how the pipeline's design and materials contributed to the risk of a pipeline failure, and failed to consider the presence of previously identified welded seam cracks as part of its risk assessment. These deficiencies resulted in the selection of an assessment method that could not detect welded seam defects and led to internal assessments of PG&E's IM program that were superficial and resulted in no improvements. Ultimately, this inadequate IM program failed to detect and repair or replace the defective pipe section.

Damage to Pipeline Facilities Caused by the Passage of Hurricanes,'' 76 FR 54531 (Sept. 1, 2011) (alerting operators to the potential for damage from Hurricane Ivan).

[13] For the impacts of climate change on precipitation; droughts, floods, and wildfire; and extreme storms, see U.S. Global Change Research Program, ''Climate Science Special Report: Fourth National Climate Assessment, Volume 1,'' at ch. 7–9 (2017).

[14] PHMSA notes that these part 192 amendments are consistent with similar provisions adopted for part 195 for hazardous liquid pipelines. See ''Pipeline Safety: Safety of Hazardous Liquid Pipelines,'' 84 FR 52260 (Oct. 1, 2019).

[15] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines): Final Rule,'' 68 FR 69778 (Dec. 15, 2003).

[16] In 2021, NACE International merged with the Society for Protective Coatings, becoming the Association for Materials Protection and Performance (AMPP). They will continue to be referred to as NACE International throughout this document.

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In response to this incident, Congress, the NTSB, and the Government Accountability Office (GAO) called for PHMSA to improve IM and address other weaknesses and gaps in the PSR. As described in more detail in the sections that follow, this is the second of three planned rulemakings that are the culmination of this rulemaking initiative.

B. Advance Notice of Proposed Rulemaking

On August 25, 2011, PHMSA published an ANPRM to seek public comments regarding potential revisions to the PSR pertaining to the safety of gas transmission and gathering pipelines. PHMSA requested comments on 122 questions spread across 15 broad issues involving IM and non-IM requirements. The issues related to IM requirements included whether the definition of an HCA should be revised and whether additional restrictions should be placed on the use of certain pipeline assessment methods. The issues related to non-IM requirements included whether revised requirements were needed for mainline valve spacing and actuation, whether requirements for corrosion control should be strengthened, and whether new regulations were needed to govern the safety of gas gathering lines and underground natural gas storage facilities. Based on the comments received on several of the ANPRM topics, PHMSA developed specific proposals for some of those topics in an NPRM that was the basis for this final rule.

C. Notice of Proposed Rulemaking and Subsequent Final Rule

On April 8, 2016, PHMSA published an NPRM seeking public comments on proposed revisions to the PSR pertaining to the safety of onshore gas transmission pipelines and gas gathering pipelines. PHMSA considered the comments it received from the ANPRM and proposed new pipeline safety requirements and revisions of existing requirements in several major topic areas. A summary of the NPRM proposals and topics pertinent to this rulemaking, the comments received on those specific proposals, and PHMSA's response to the comments received, is provided under section III (Discussion of NPRM Comments, GPAC Recommendations, and PHMSA Response).

On October 1, 2019, PHMSA promulgated a subset of the rules proposed in the NPRM by issuing the first of three planned final rules. In that rule, PHMSA addressed gas transmission pipelines and established minimum Federal safety standards for MAOP reconfirmation, pipeline physical material properties verification, the expansion of integrity assessments beyond HCAs, the consideration of seismicity in an operator's risk assessment and P&M measures, ILI tool launcher and receiver safety, MAOP exceedance reporting, and strengthened requirements for IM assessment methods.

This final rule, the second of three planned rules, finalizes several proposed amendments in the NPRM related to gas transmission pipelines, including provisions related addressing repair criteria, IM improvements, cathodic protection, MOC processes, and other related amendments. A separate rulemaking, dealing with the safety of onshore gas gathering pipelines, was the subject of a final rule published on November 15, 2021, and extended reporting and safety requirements to certain gathering pipelines that were formerly not subject to Federal safety oversight. PHMSA estimated in that Gas Gathering Final Rule that there were over 400,000 miles of gas gathering pipelines that were not subject to minimum Federal pipeline safety standards, including basic incident and mileage reporting. The Gas Gathering Final Rule extended annual and incident reporting requirements to all gathering pipelines and defined a new category of ''Type C'' gathering pipelines to address the safety of larger-diameter, higher-pressure onshore gathering pipelines that were formerly unregulated. The scope of the requirements for Type C gas gathering pipelines are risk-based; basic damage prevention provisions apply to all Type C gas gathering pipelines while other safety requirements apply to larger-diameter Type C gas gathering pipelines or those Type C gas gathering pipelines that are located near buildings intended for human occupancy.

III. Discussion of NPRM Comments, Gas Pipeline Advisory Committee Recommendations, and PHMSA Response

The comment period for the NPRM ended on July 7, 2016. PHMSA received approximately 300 submissions to the docket containing thousands of comments on the NPRM. Submissions were received from the NTSB; groups representing the regulated pipeline industry; groups representing public interests, including environmental groups; State utility commissions and regulators; members of Congress; individual pipeline operators; and private citizens. PHMSA also received late-filed comments to this rulemaking from the major industry trade associations and others following advisory committee meetings as discussed below. Consistent with DOT Order 2100.6 and 190.323, PHMSA considered all comments, including those that were filed late, given their relevance to the rulemaking and the absence of additional expense or delay resulting from considering these comments.

Some of the comments PHMSA received in response to the NPRM were considered in finalizing the 2019 Gas Transmission Rule targeted at statutory mandates, while other comments were considered in response to the third final rule on gas gathering pipelines (under RIN 2137–AE38). In this final rule, PHMSA considers those comments that are relevant to repair criteria, IM improvements, cathodic protection, MOC, and other related amendments. PHMSA does not address the comments on pipeline safety issues that were beyond the scope of the NPRM and, therefore, beyond the scope of this final rule. However, that does not mean that PHMSA determined the comments lack merit or do not support additional rules or amendments. Such issues may be the subject of other existing rulemaking proceedings or may be addressed in future rulemaking proceedings. The remaining comments reflect a wide variety of views on the merits of particular sections of the proposed regulations.

The Technical Pipeline Safety Standards Committee, commonly known as the Gas Pipeline Advisory Committee (GPAC or ''the committee''), is a statutorily mandated advisory committee that advises and comments on PHMSA's proposed safety standards, risk assessments, and safety policies for natural gas pipelines prior to their final adoption. The GPAC is one of two pipeline advisory committees focused on technical safety standards that were established under the Federal Advisory Committee Act (Pub. L. 92–463) and section 60115 of the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*). Each committee consists of approximately 15 members, with membership equally divided among Federal and State agencies, regulated industry, and the public. The committees consider the ''technical feasibility, reasonableness, cost-effectiveness, and practicability'' of each proposed pipeline safety standard and provide PHMSA with recommended actions pertaining to those proposals.

Due to the size and technical detail of the NPRM, the GPAC met 5 times in 2017 and 2018 to discuss the proposed

regulations applicable to gas transmission pipelines. The GPAC convened one time in 2019 to discuss the provisions related specifically to gas gathering pipelines.[17] During those meetings, the GPAC considered the specific regulatory proposals of the NPRM and discussed various comments made on the NPRM's proposal by stakeholders, including the pipeline industry at large, public interest groups, and government entities. To assist the GPAC in its deliberations, PHMSA presented a description and summary of the major proposals in the NPRM and the comments received on those issues. Stakeholders could comment on the proposals during the meeting prior to the committee discussion. PHMSA assisted the committee in fostering discussion and developing recommendations by providing direction on which issues were most pressing.

For the proposals addressed in this final rule, the committee came to consensus when voting on the technical feasibility, reasonableness, cost-effectiveness, and practicability of the NPRM's provisions. In many instances, the committee recommended changes to certain proposals that the committee found would make the rule more feasible, reasonable, cost-effective, or practicable.

This section discusses the substantive comments on the NPRM that were submitted to the docket, as well as the GPAC's recommendations. They are organized by topic and include PHMSA's response to, and resolution of, those comments.

A. IM Clarifications—§§ 192.917(a)–(d), 192.935(a)

i. Threat Identification, Data Collection, and Integration—§ 192.917(a) and (b)

1. Summary of PHMSA's Proposal

Subpart O of 49 CFR part 192 prescribes requirements for managing pipeline integrity in HCAs and requires that operators identify and evaluate all potential threats to each covered pipeline segment. Operators are required to identify threats to which the pipeline is susceptible, collect data for analysis, and perform a risk assessment that informs the operator's baseline assessment schedule and reassessment intervals as well as any additional P&M measures that may be needed for the covered segment. The regulations also require operators to address particular threats, such as third-party damage and manufacturing and construction defects. For these requirements, the regulations reference, through incorporation, ASME/ANSI B31.8S.

For threat identification, the regulations in § 192.917 specify that the potential threats operators must consider include, but are not limited to, the threats listed in section 2 of ASME/ANSI B31.8S. Those threats are grouped into time-dependent threats, static or resident threats, time-independent threats, and human error. In performing data gathering and integration, operators must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, operators must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, which are the year of installation; pipe inspection reports; leak history; wall thickness; diameter; past hydrostatic test information; gas, liquid, or solid analysis; bacteria culture test results; corrosion detection devices; operating parameters; and operating stress level. An operator must also conduct a risk assessment that follows ASME/ANSI B31.8S section 5.

In a risk-based IM approach, data collection and integration is the backbone of an effective IM program. The PG&E incident exposed several problems in the way operators collect and manage pipeline condition data, showing that some operators have inadequate records regarding the physical and operational characteristics of their pipelines. The use of erroneous information leads to insufficient understanding of pipeline risks and incorrect integrity-related decision making. PG&E's IM program was missing or misidentified data elements that were necessary to characterize risk correctly and establish and validate MAOP, which is critically important for providing an appropriate margin of safety to the public.

Threat identification, data collection, and data integration are basic pillars on which IM was founded with the issuance of the 2003 IM rule. As specified in § 192.907(a), operators were to start with a framework, evolve that framework into a more detailed and comprehensive program, and continually improve their IM programs.[18] Operators would accomplish this constant improvement, in part, through learning about the IM process itself and learning more about the physical condition of their pipelines via IM assessments and the development of that data.

Data collection for new pipeline construction is relatively simple. However, collecting missing material property records for pipeline segments that have been in the ground for years can be challenging, as such data collection must be completed through integrity assessments or excavations. Operators are required to identify missing data and apply conservative assumptions, but incomplete data presents issues for risk assessment. The over-application of assumptions in the absence of real data, even if those assumptions are conservative, can lead to skewed or otherwise inaccurate risk analysis results.

In the NPRM, PHMSA proposed to revise § 192.917 to include specific requirements for collecting, validating, and integrating pipeline data. These requirements would add further specificity to the data integration regulations, list specific pipeline attributes that must be included in these analyses, explicitly require that operators integrate analyzed information, and require that data be verified and validated. PHMSA also proposed to require that operators use validated, objective data to the maximum extent practical. To the degree that subjective data from subject matter experts (SME) must be used, PHMSA would require that operator programs include specific features to compensate for SME bias, including training SMEs to recognize or avoid bias, and using outside technical experts or independent expert reviews to assess SME judgment and logic. Further, in § 192.917(b)(3), PHMSA proposed to require operators to identify and analyze spatial relationships among anomalous information (*e.g.,* corrosion coincident with foreign line crossings and evidence of pipeline damage where overhead imaging shows evidence of encroachment), stating that storing or recording the information in a common location, including a geographic information system (GIS) alone, is not sufficient.

2. Summary of Public Comment

Many stakeholders agreed with PHMSA that verified and validated data is important for data integration and threat analysis. The NTSB expressed support for the proposed additions to the IM analysis requirements and commented that expanded pipeline record and data requirements are a significant safety improvement in the management of pipelines through their service lifecycle. However, certain

[17] Specifically, the committee met on January 11–12, 2017; June 6–7, 2017; December 14–15, 2017; March 2, 2018; March 26–28, 2018; and June 25–26, 2019. Information on these meetings can be found at *regulations.gov* under docket no. PHMSA–2011–0023 and at PHMSA's public meeting page: *https://primis.phmsa.dot.gov/meetings/.*

[18] See 68 FR 69789.

stakeholders had concerns with PHMSA's specific proposed changes.

PHMSA also received comments from the industry on the feasibility of threat identification, data gathering, and integration. The American Petroleum Institute (API) stated that while the totality of attributes listed in proposed § 192.917 should not pose a major burden on the industry, some specific attributes listed may not be feasible to obtain in practice. Enterprise Products stated that including just four or five attributes that point to a specific conclusion would be more useful than the lengthy list of attributes in the proposed provisions. A few commenters requested PHMSA clarify what they meant by ''data integration, verification, and validation,'' as these terms were not clear.

The Interstate Natural Gas Association of America (INGAA) and the Texas Pipeline Association (TPA) expressed concern that the proposed provisions are more prescriptive than the ASME/ANSI standard that is referenced in the current IM requirements. INGAA also commented that PHMSA's proposed inclusion of specific attributes from ASME/ANSI B31.8S in the regulatory text alongside the existing incorporation by reference of that standard could cause confusion. INGAA further stated that PHMSA should retain the current regulatory language requiring operators to ''consider'' the relevant data for covered segments and similar non-covered segments, instead of adopting the proposed provisions that would require data evaluation for non-covered segments. INGAA also stated that many of the data elements required by ASME/ANSI B31.8S are not available for older pipelines, which can include non-covered segments. INGAA and other commenters also asserted that PHMSA should provide sufficient time for operators to comply with the proposed data validation and integration requirements given the expansion of § 192.917(b)(1) to non-covered segments.

Several commenters provided input on PHMSA's proposed requirements to address SME bias. INGAA suggested PHMSA should delete the references to SME bias listed in § 192.917(b)(2) and replace the text with more general language to include peer reviews and external SME verification, citing this alternative as more consistent and clearer than what PHMSA proposed. National Fuel stated that using outside technical experts for bias control would be unnecessarily costly to pipeline operators. The American Gas Association (AGA) asserted that using outside technical subject matter experts for bias control is already standard practice within the industry and that it is not necessary to codify it into regulation. PG&E also suggested improvements to the section, stating that there is not an existing industry standard to provide guidance on what constitutes an outside technical expert to perform this specific function, and PHMSA should provide further guidance on this topic.

Several industry trade groups provided input on the proposed language in § 192.917(b)(3) that would require operators to identify and analyze the spatial relationship among anomalous information (*e.g.,* corrosion coincident with foreign line crossings and evidence of pipeline damage where overhead imaging shows evidence of encroachment). TPA stated that it disagreed with PHMSA's proposal in this paragraph and commented that this requirement would impose a financial burden on smaller operators. PG&E asserted that the proposed language in § 192.917(b)(3) should be removed entirely since it was not clear how to comply with these requirements.

At the GPAC meeting on June 7, 2017, the committee noted that the NPRM's proposed revisions to § 192.917 do not include a way for operators to address the lack of availability of some data sets. The committee suggested that operators could assume the pipeline segment is susceptible to the threat associated with the missing data. The committee also questioned the purpose for the extensive, prescriptive data list, with some members believing it would turn into a compliance paperwork exercise without safety benefit. This, in turn, led to a discussion of how an operator demonstrates to a regulator that it is performing an effective risk analysis and whether that is a checklist of items or performing actions to generate better safety outcomes. Some committee members suggested PHMSA clarify that operators should only collect the pertinent data for operations and maintenance (O&M) tasks.

Committee members representing the industry noted the rule has no timeframe for the implementation of data collection and challenged the conclusion in the preliminary regulatory impact assessment (PRIA) that the data collection elements had a cost of zero, as databases may need to be upgraded to implement the listed attributes. Members representing the industry also requested PHMSA remove the proposed requirement to address SME bias; however, other committee members representing the public noted that SME bias in risk analysis is recognized across different disciplines and reflects a need to address how humans think about risk. Certain committee members representing the industry were also concerned that the requirements mandated the use of a GIS, which might be impractical for small operators.

Following the discussion, the committee voted 11–0 that the proposed rule, as published in the **Federal Register**, with regard to the provisions for IM clarifications regarding threat identification, data collection, and data integration, were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the list of pipeline attributes in the section to be more consistent with the existing regulations and the ASME/ANSI B31.8S standard, and if PHMSA also added language requiring operators to collect data that is pertinent and that a prudent operator would collect. The committee also recommended PHMSA require operators to have implementation procedures in place 1 year after the effective date of the rule, with full incorporation of all listed attributes by 3 years after the effective date of the rule, and strike requirements for operators to use a GIS in complying with these provisions. Finally, the committee recommended that PHMSA address SME bias by considering some of the specific suggestions made by committee members at the meeting, including striking or revising the last sentence of the provisions.

3. PHMSA Response

The current regulations at § 192.917(b) explicitly require that, at a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S. Operators may not ignore that requirement to collect the minimum set of data needed for a robust threat evaluation and risk assessment. PHMSA agrees that some assumptions regarding threat applicability based upon pipe type, operating parameters, and operating environment (*i.e.,* weld seam type, manufacturing date, coating type, operating pressure versus percentage specified minimum yield strength (SMYS), operating temperature, lack of cathodic protection (CP) or the time when CP was placed on the system, and location) can be made even if the pertinent data is missing. For example, a lack of CP on a pipeline system would mean that the pipeline is more prone to external corrosion, no matter what type of external coating is on the pipe. High operating temperatures, pressures, and a lack of quality pipe coating can also be risk factors for cracking.

Regarding INGAA's comment on retaining the current regulatory

language requiring operators to ''consider'' the relevant data for covered segments and similar non-covered segments rather than adopting the proposed provisions that would require data evaluation for non-covered segments, PHMSA reminds operators that the current requirement states that operators must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. At a minimum, operators must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S and consider both on the covered segment and similar non-covered segments the data and conditions specific to each pipeline. PHMSA's clarification in this final rule that operators must ''analyze'' the information that they are already required to collect, integrate, and consider, is consistent with the existing requirement, as performing those actions is, essentially, an analysis. Nevertheless, PHMSA is changing ''consider'' to ''analyze'' to reinforce that operators must have documentation demonstrating that they have reviewed the data for similar vintage pipe to determine whether they have threats or not that should be remediated.

PHMSA further disagrees that it is appropriate to allow industry to continue to ''consider'' data elements selectively or that only specifying a few required data elements is the best approach. While some pipelines without associated data may not pose a risk, some may pose a significant risk. Comprehensive data is the best way to ensure an appropriate assessment and, in turn, reduction of risk. The addition of the specific data elements in the regulatory text clarifies PHMSA's expectations of data collection. PHMSA agrees, however, that some data elements may not be pertinent to all pipeline segments. Therefore, in this final rule, PHMSA is revising the proposed requirement to specify that the operator must collect ''pertinent'' data ''about pipeline attributes to assure safe operation and pipeline integrity, including information derived from operations and maintenance activities,'' as recommended by the GPAC. Regarding the cost of this data collection, all the proposed elements were listed in ASME/ANSI B31.8S. As that standard has been incorporated by reference since 2004 for covered segments (*i.e.,* HCAs), collecting the listed data should not be a new or an extensive exercise for any prudent operator with appropriate processes in place. While specifying the list of data elements in the regulatory text is new, the elements listed have been incorporated by reference since the promulgation of subpart O and are not more prescriptive than the current regulations. Further, PHMSA disagrees that continuing to incorporate by reference ASME/ANSI B31.8S as well as specifying individual data elements will confuse operators.

Additionally, in response to comments and the GPAC recommendation, PHMSA is revising the listing of data elements to be more consistent with ASME/ANSI B31.8S. In some cases, PHMSA has clarified the meaning of generic terms in the data collection list found in ASME/ANSI B31.8S within this final rule. For example, where the ASME/ANSI standard lists ''material properties,'' PHMSA has elaborated by specifying these are ''material properties including, but not limited to, grade, SMYS, and ultimate tensile strength.'' In another example, where the standard lists ''pipe inspection reports,'' PHMSA has itemized, in this final rule, the pipe inspections required by part 192 and that are commonly performed by operators.

PHMSA agrees with commenters that sufficient time should be allotted for operators to comply with the data integration requirements. However, PHMSA also agrees with the comments made that operators should have been collecting and accounting for the pertinent items of this data set since the publication of the original IM rule almost 20 years ago. Therefore, in this final rule, PHMSA is providing a phased-in timeframe. The GPAC recommended that the implementation timeframe should begin in year 1, with full incorporation by 3 years. Given the existing requirements for collecting and using the data elements from ASME/ANSI B31.8S, and given the discussion at the GPAC meetings and the public comments received, PHMSA has revised this final rule to require that an operator must begin data integration on the effective date of the rule and integrate all attributes within 18 months of this rule's publication date.

Regarding comments calling for clarification of what ''data integration, verification, and validation'' meant, PHMSA notes that, at a minimum, an operator should consider the same set of data on a periodic basis and analyze changes and trends that would indicate the need for additional integrity evaluations.

Regarding SME bias, PHMSA believes that it is important for operators to address SME bias in data collection and risk assessment to account for the reality of how humans think about risk. Operators should take this into consideration when incorporating SME opinion as fact or when treating input from all SMEs as equivalent. While some operators may effectively account for SME bias, PHMSA has not observed this to be universal practice in the industry. To the point commenters made that using outside technical experts for bias control is unnecessarily costly, PHMSA notes that the use of outside technical experts would be optional: this final rule contemplates that operators could also employ training to ensure information provided by their own SMEs is consistent and accurate. While commenters also correctly noted that there is not an existing industry standard as to what constitutes an outside technical expert or an independent technical expert for SME bias control, an operator is ultimately responsible for determining the appropriateness and conductors of such a review. As a part of such a review, should an operator decide to have another SME review input from another SME, the operator must use a qualified SME—*e.g.,* an individual with formal or on-the-job technical training in the technical or operational area being analyzed, evaluated, or assessed. Operators would be required to document that the SME is appropriately knowledgeable and experienced in the subject being assessed.

PHMSA was persuaded, consistent with a GPAC recommendation, that some adjustments to the rule language are appropriate for clarity, or to eliminate redundant language, within the non-exhaustive list of specific types of data to be collected at § 192.179(a) and (b). Specific changes adopted in this final rule include the following:

- Section 192.917(a)(2): deleted a redundant reference to ''or equipment defects;''
- Section 192.917(b)(1)(iii): deleted explicit material properties (*e.g.,* hardness, chemical composition) from a non-exhaustive list of material properties;
- Section 192.917(b)(1)(xxiv): added ''seam cracking'' within the list of pipe operational and maintenance inspection reports to be reviewed;
- Section 192.917(b)(1)(xxv): deleted a redundant reference to ''outer/inner diameter corrosion monitoring;''
- Section 192.917(b)(1)(xxviii): eliminated specific examples of ''encroachments;'' and
- Section 192.917(b)(1)(xxxvi): deleted a redundant savings clause for ''other pertinent information'' when the lead-in to the section noted that the information listed was non-exhaustive.

PHMSA has also, consistent with a recommendation by the GPAC revised the rule by (1) requiring that operators employ adequate control measures for SME input to ensure consistent and accurate information rather than ''correct'' SME ''bias;'' and (2) requiring that operators document the names and qualifications of individuals who approve SME input rather than document the names of the SMEs and the information provided.

Concerning the use of a GIS, the NPRM's proposed revisions to § 192.917 were not intended to imply that all operators were required to implement a GIS system but were meant to clarify that data integration is not achieved solely by maintaining spatially located data in a GIS system. Accordingly, PHMSA has revised this final rule as recommended by the GPAC to delete reference to the use of a GIS system and maintain the core requirement to identify and analyze spatial relationships among anomalous information.

A. IM Clarifications—§§ 192.917(a)–(d), 192.935(a)

ii. Risk Assessment Functional Requirements—§ 192.917(c)

1. Summary of PHMSA's Proposal

Section 192.917(c) requires operators to perform a risk assessment as part of an effective IM program. A risk assessment is an important element of a good IM plan. PHMSA analyzed the issues related to risk assessments that the NTSB identified in its investigation and held a workshop on July 21, 2011, to address perceived shortcomings in the implementation of IM risk assessments. PHMSA also sought input from stakeholders on these issues in the ANPRM. Based on the input received from both the ANPRM and the workshop, PHMSA determined that additional clarification was needed to emphasize the functions that risk assessments must accomplish and to elaborate on effective processes for risk management, both of which are critical to effective IM.

To address these issues, PHMSA proposed to clarify the risk assessment aspects of the IM regulations at subpart O by including the following functional requirements for risk assessments that operators should perform to assure pipeline integrity:

- Evaluate the effects of interacting threats;
- Ensure validity of the methods used to conduct the risk assessment;
- Determine additional P&M measures needed;
- Analyze how a potential failure could affect an HCA, including the consequences of the entire worst-case incident scenario, from initial failure to incident termination;
- Identify how each risk factor, or each combination of risk factors that simultaneously interact, contribute to risk at a common location;
- Account and compensate for uncertainties in the model and the data used in the risk assessment; and
- Evaluate risk reduction associated with candidate activities, such as P&M measures.

2. Summary of Public Comment

Public interest groups supported PHMSA's proposed revisions at § 192.917(c) to strengthen the functional requirements for risk assessment models. The Pipeline Safety Trust (PST) stated that the risk assessment models currently used by pipeline operators are inadequate and further noted that the proposed provisions could go farther to advance risk assessment quality. Other GPAC members representing the public supported the proposed revisions at § 192.917(c) during the committee meetings and noted that the NPRM language for this topic was written using a risk-informed approach that articulated the functions and purposes of risk assessments without being prescriptive as to the method or process to be used, which is consistent with IM principles.

Multiple industry trade associations and individual operators acknowledged the importance of risk assessments but believed that the proposed revisions at § 192.917(c) were too prescriptive. Several individual operators emphasized their voluntary efforts to improve their risk models and disagreed that the industry's risk models needed further prescription.

Many commenters emphasized that different pipeline systems are susceptible to different threats and believed that operators are best suited to determine which threat analyses are relevant to their systems. Multiple operators expressed the opinion that the proposed revisions at § 192.917(c) would require operators to expand datasets substantially but would contribute little benefit to risk identification, suggesting instead that integrating unnecessary datasets would distract from other safety efforts. AGA and several individual operators requested that PHMSA give operators discretion to select which data sets to incorporate into risk assessments for their system.

Some commenters requested that PHMSA specify what the NPRM meant when it proposed to revise § 192.917(c) to require operators to ''validate'' data. These commenters expressed doubts regarding the technical feasibility of implementing the proposed regulations in § 192.917(c), noting that some of the data PHMSA proposed requiring for the validation of risk assessment models is not available. These commenters proposed that operators be permitted to apply conservative values or values determined using engineering judgement. Southwest Gas Corporation, Paiute Pipeline, and Consumers Pipeline expressed concern that developing the newly required datasets would require the usage of ILI tools that their pipelines are not configured to accommodate. These commenters stated that gathering these datasets would present costs that were not captured by PHMSA's PRIA because PHMSA did not account for the cost of making lines piggable.

Multiple commenters were concerned that the proposed revisions would make operators' current relative risk models invalid and would require a transition to quantitative or probabilistic risk models. Similarly, API agreed with that assessment and noted that quantitative and probabilistic models are not useful or appropriate for the analysis, prediction, or prevention of low-frequency, high-consequence events such as the PG&E incident. Further, API noted that the probabilities of certain infrequent circumstances and conditions occurring at a single location and single time are so low that the quantitative or probabilistic risk models would not identify them because there are no statistics available from which to predict them. AGA asserted that the proposed requirements deviate from industry standards and that PHMSA did not provide sufficient justification for this departure. Commenters also emphasized the high costs associated with implementing quantitative risk models, which can include the procurement of specialist expertise, development of new datasets, and transition to a GIS or other new database management system.

Kern River requested clarification regarding which elements of § 192.917 need to be included in an operator's risk model and which elements only need to be included in the overall IM plan. They noted that integrity assessment method determinations, repair decisions, P&M measures selection, root cause analyses, and similar pipe studies all play a part in the overall IM plan and have at times overlapping, but also unique, requirements for data gathering, integration, and threat analysis.

AGA and several individual operators expressed concerns that the proposed rule does not provide a timeline for implementing new risk assessment requirements, thereby implying that operators must implement new requirements by the rule's effective date. Multiple operators and industry trade associations requested that operators be permitted to develop their own implementation schedules or provided suggestions for specific implementation schedules. For example, Enterprise Products requested that PHMSA include a 2-year implementation period for operators to incorporate the data integration and risk assessment requirements into their IM programs.

At the GPAC meeting on January 12, 2017, some committee members noted that any revisions to the risk assessment requirements should be deferred until after PHMSA's Pipeline Risk Modeling Work Group issues its pipeline system risk modeling technical document.[19] There was broad support from the committee for the revisions to § 192.917(c) proposed in the NPRM, with members noting the language was consistent with IM principles and was written using a performance-based approach that articulated the functions and purposes of risk assessment without being prescriptive as to the method or process needing to be used. However, some committee members representing the industry expressed concern with the use of the term ''probability'' in the NPRM's proposed revisions to § 192.917(c), which seemed to imply PHMSA intended for operators to be using probabilistic risk assessment techniques.

Following the discussion, the committee voted 11–0 that the proposed provisions for the risk assessment requirements were technically feasible, reasonable, cost-effective, and practicable if PHMSA modified the proposed rule to restore the reference to ASME/ANSI B31.8S, section 5, to clarify that other methods besides probabilistic techniques may be used; change the term ''probability'' to ''likelihood'' and delete the term ''risk factors'' from § 192.917 (c)(2); and provide a 3-year phase-in period for risk assessments to meet the functional objectives specified in § 192.917(c).

3. PHMSA Response

On March 6, 2020, PHMSA published the final report titled ''Pipeline Risk Modeling—Overview of Methods and Tools for Improved Implementation'' from the joint PHMSA/industry working group on risk modeling.[20] However, PHMSA notes that the report is focused exclusively on the models employed and ''best practices'' for using them. The working group did not address other aspects of the proposed rule, including how a risk assessment is used.

PHMSA believes that the revisions to § 192.917(c) are important to include in this rulemaking now, as many operators have not substantially improved their risk assessment techniques or models since the early initial efforts to prioritize baseline assessment plans in 2004, with the findings from the PG&E incident being a prime, national example. Therefore, PHMSA is establishing explicit minimum standards for the functional requirements of a risk assessment to help assure that operators will achieve this specific aspect of a ''more detailed and comprehensive'' program as discussed in the 2003 IM rule.

In the NPRM's proposed revisions to § 192.917(c), when PHMSA used terms such as ''probability'' and ''risk factors,'' it was not intended to imply that an operator must perform probabilistic risk analysis. To address this, PHMSA has modified the rule language to replace the term ''probability'' with ''likelihood'' and restored the reference to ASME/ANSI B31.8S, section 5, for acceptable risk assessment methodologies as recommended by the GPAC. Similarly, and as also recommended by the GPAC, PHMSA has deleted the phrase ''or risk factors'' from paragraph § 192.917(c)(2) for clarity. Whichever risk assessment methodology an operator chooses, the result must meet the functional requirements and accomplish the purposes specified in this final rule.

PHMSA notes that all data elements specified in § 192.917(b) are important for a robust risk assessment. While operators do have the discretion to expand their data collection efforts, this minimum defined data set is required to be used. As was emphasized by multiple operators in their comments, each pipeline system is susceptible to different threats, and the individual operator is best suited to determine these threats. However, an operator needs the specified data elements to identify threats objectively. As noted in the previous section, PHMSA has modified the rule to refer to the ''pertinent'' data elements, including information derived from O&M activities that assure safe operation and pipeline integrity. This revision clarifies that data elements that are not pertinent for a given pipeline segment need not be included in a risk assessment.

Pertaining to comments regarding the validity of the method used, an operator must ensure the soundness of the risk modelling method they are using applicable to the threats to a given pipeline segment, including its specific leak or failure history. To Kern River's comment as to which elements of § 192.917 need to be included in an operator's risk model and which elements need to be included in an operator's IM plan, PHMSA will note that integrity assessment method determinations, repair decisions, P&M measure selection, and root cause analyses are examples of items that could be included in an operator's risk model based on the particular types of threats being assessed. The existing regulations state that a ''particular threat'' is an identified threat being assessed for each covered segment.

As discussed above, some commenters claimed there would be high costs associated with implementing quantitative risk models, which might include the procurement of specialist expertise, the development of new data sets, and a transition to a GIS or other new database management system. PHMSA notes that operators can use the same data they have been, and are currently, collecting when implementing a quantitative risk model. Operators do not necessarily have to ''recollect'' or otherwise change their existing data to use a probabilistic risk model.

Given the state of some operators' risk assessment programs, PHMSA is persuaded that it is reasonable to allow operators a reasonable amount of time to upgrade their risk assessment models, methodologies, and analyses. However, this is an important provision that operators need to implement as soon as practicable. Therefore, and to be more consistent with the implementation for the data attributes discussed earlier, PHMSA is modifying this final rule to allow an 18-month implementation period for this provision.

A. IM Clarifications—§§ 192.917(a)–(d), 192.935(a)

iii. Threat Assessment for Plastic Pipe—§ 192.917(d)

1. Summary of PHMSA's Proposal

PHMSA proposed to add to the regulations examples of threats unique to plastic pipe that operators must consider, such as poor joint fusion practices, pipe with poor slow crack

[19] For more information on the work group and its efforts, see *https://www.phmsa.dot.gov/pipeline/risk-modeling-work-group/risk-modeling-work-group-overview.*

[20] *https://www.phmsa.dot.gov/news/now-available-phmsa-report-pipeline-risk-modeling-overview-methods-and-tools-improved-0.*

growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading. The proposed revisions would not otherwise change the current requirements of § 192.917(d).

2. Summary of Public Comment

PHMSA did not receive any public comments on this section. At the GPAC meeting on June 7, 2017, PHMSA noted in its presentation to the committee that there were no public comments on the issue. Subsequently, the GPAC voted 11–0 that the proposed changes to the provisions for IM clarifications for threat assessments for plastic pipe were technically feasible, reasonable, cost-effective, and practicable, and they did not recommend any additional changes to § 192.917(d).

3. PHMSA Response

Since PHMSA did not receive any public comments or additional GPAC recommendations regarding threat assessment for plastic pipe, the final rule includes the requirement in § 192.917(d) as proposed in the NPRM. PHMSA proposed these changes to highlight these potential threats to both operators and inspectors, and finalizing these requirements will provide additional safety and enforcement awareness.

A. IM Clarifications—§§ 192.917(a)–(d), 192.935(a)

iv. Preventive and Mitigative Measures—§ 192.935(a)

1. Summary of PHMSA's Proposal

PHMSA's inspection experience shows that some operators do not implement additional P&M measures based on the evaluation required at § 192.935(a). PHMSA believes that strengthening requirements related to operators' use of insights gained from their IM programs is prudent to ensure effective risk management. Therefore, PHMSA proposed to clarify the expectation that operators use knowledge from risk assessments to establish and implement adequate P&M measures and provided more explicit examples of the types of P&M measures for operators to evaluate.

2. Summary of Public Comment

Several commenters requested that PHMSA revise the requirements at § 192.935(a) to remove the requirement for operators to perform all the listed measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in an HCA. These commenters stated that requiring operators to perform all the measures listed at § 192.935(a) negates the need for a risk analysis, as the rule would then require that operators perform each of the listed actions regardless of whether conditions warrant these actions or whether past efforts have been taken. INGAA suggested that PHMSA should keep the existing language, which states that an operator must base the additional measures on the threats the operator has identified to each pipeline segment. GPAC members representing the industry echoed INGAA's claims during the committee meetings.

During the GPAC meeting on June 7, 2017, the GPAC noted that PHMSA's proposed changes removed a statement that an operator must base additional P&M measures on the threats an operator has identified for each pipeline segment. The proposed text, the members believed, implied an operator would be required to evaluate and implement each listed P&M measure every time. Based on PHMSA's webinars and other discussions, the committee members didn't believe that was PHMSA's intent.

Following that discussion, the committee voted 11–0 that the proposed provisions for strengthening the requirements for applying IM knowledge were technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified it was not the agency's intent to require that all listed P&M measures be implemented, and that operators ''must consider'' the listed items.

3. PHMSA Response

PHMSA agrees that all listed measures are not mandatory for implementation in all cases. Requiring an operator to implement P&M measures against threats that might not be applicable to their particular system could be overly burdensome. However, PHMSA has determined that requiring operators to consider the listed measures in their risk analyses and apply them to threats as appropriate is a practical requirement. As recommended by the GPAC, the final rule has been modified to reflect that position; each operator will be required to consider the listed measures and determine the appropriateness of each for their system.

B. Management of Change—§§ 192.13 & 192.911

1. Summary of PHMSA's Proposal

Section 192.911(k) requires that an operator's IM program include a MOC process as outlined in ASME/ANSI B31.8S, section 11. That document guides operators to develop formal MOC procedures to identify and consider the impact of major and minor changes to pipeline systems and their integrity. These changes can include technical, physical, procedural, and organizational changes, and they can be either temporary or permanent changes. Per ASME/ANSI B31.8S, section 11, an operator's MOC process should include the reason for the change, the authority for approving changes, an analysis of the implications of the change, the proper acquisition of the necessary work permits, appropriate documentation, communications of the change to any affected parties, time limitations of the change, and the qualification of staff. The document notes that changes to a pipeline system might require changes to an operator's IM program; similarly, changes to an IM program might also cause changes to a pipeline system. If changes in land use (*e.g.,* increased population) would affect the potential consequence of an incident or the likelihood of an incident occurring, such a change should be reflected in an operator's IM program. The operator should also reevaluate threats accordingly. In short, the MOC process outlined by ASME/ANSI B31.8S helps to ensure that an operator's IM process remains viable and effective as changes to pipeline systems occur or new data becomes available.

Inadequately reviewed or documented design, construction, maintenance, or operational changes can contribute to pipeline failures. In the PG&E incident, the NTSB investigation determined that a substandard piece of pipe was substituted in the field without proper authorization, design review, or approval. PHMSA has subsequently determined that more specific attributes of the MOC process should be explicitly codified within the text of §§ 192.13 (general requirements) and 192.911(k) (IM requirements). As a result, PHMSA proposed to require that operators have a MOC process that includes the reasons for the change; the authority for approving changes; an analysis of implications; the acquisition of required work permits; and evidence documenting communication of the change to affected parties, time limitations, and the qualification of staff.

2. Summary of Public Comment

Public interest groups, such as the PST, and the National Association of Pipeline Safety Representatives (NAPSR) agreed with and supported the proposed MOC provisions, stating that these provisions would enhance pipeline safety. Several individual pipeline operators and trade associations opposed the proposed MOC provisions, stating that the provisions are generally too broad and would be applied to many routine activities that already have established procedures. More specifically, AGA stated that they would create a new requirement for each transmission operator to have a formal MOC process to document and evaluate all changes to pipelines and processes. They further stated that the proposed revisions are unnecessary due to current industry progress related to MOC and the voluntary adoption of industry consensus standards.

Several commenters opposed the proposed addition of four types of changes (design, environmental, operational, and maintenance), asserting that these elements are not included in current industry standards or recommended practices. Similarly, INGAA asserted that PHMSA should eliminate the changes it proposed to § 192.13 that go beyond the recommendations of ASME/ANSI B31.8S. These commenters stated that PHMSA significantly underestimated the impact and burden caused by codifying and expanding the scope of MOC.

Several commenters, including AGA, API, and INGAA, opposed the proposed immediate implementation of the MOC provisions, with some commenters requesting an implementation period of 1 to 5 years. These commenters stated that the proposed changes were significant and would need to be incorporated into existing MOC processes, and that additional time would be needed to complete this in an effective manner. Many commenters also expressed concern over the retroactive application of the proposed MOC provisions.

At the GPAC meeting on January 12, 2017, the committee voted 8—2 that the proposed MOC revisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA provided a 2-year phase-in period for the regulations as they pertain to non-IM pipeline assets, provided a notification procedure for justified extensions, clarified the requirements only covers significant changes that affect safety and the environment, and clearly stated that the revisions do not apply to distribution or gathering lines. The dissenters in the vote (representatives from the Environmental Defense Fund (EDF) and PST) were members representing the public, who thought that the proposed revisions were acceptable as proposed in the NPRM, the phase-in period recommended by the majority of the GPAC was too long, and that there was no reason that the proposed revisions should not apply to gathering lines.

3. PHMSA Response

PHMSA believes that an operator must understand the impacts that their decisions have on safety and the environment. Therefore, PHMSA believes that specifying the types of changes that must be addressed under a MOC program is appropriate. PHMSA also believes that the proposed changes to the MOC provisions conform with the requirements and intent of ASME/ANSI B31.8S.

However, based on the comments received and GPAC recommendations, PHMSA is persuaded that, as published in the NPRM, the language of proposed § 192.13(d) could be overly broad. Therefore, PHMSA has revised the requirement to specify the requirement applies to a ''significant change that poses a risk to safety or the environment'' to limit the application of this requirement to significant changes, as the GPAC recommended. Additionally, and as also recommended by the GPAC, PHMSA is specifying that § 192.13(d) is not retroactive and applies only to onshore transmission pipelines (*i.e.,* not gathering or distribution pipelines).[21]

PHMSA agrees that operators should be afforded time to comply with this new requirement, but also believes that operators can apply this process to non-HCA assets more promptly than the period that the GPAC recommended. Therefore, operators have 18 months for the MOC process to be fully incorporated for non-HCA pipeline segments. PHMSA is also including a notification procedure in accordance with § 192.18 for operators to apply for an extension, of up to 1 year, of the compliance deadline. PHMSA believes including this compliance deadline strikes a balance between the GPAC recommendation and the implementation of a procedure that operators already have in place for HCA pipeline segments, and including a notification procedure to provide operators with more time, if necessary, effectively implements the GPAC recommendations.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

i. Applicability

1. Summary of PHMSA's Proposal

Incidents attributed to corrosion continue to occur, which demonstrates that the current requirements can be more effective at preventing incidents caused by certain types of corrosion. This includes compromised pipe or pipe coating caused by damage from construction, cathodic protection deficiencies, interference currents, and internal corrosion. As a result, PHMSA proposed several changes to the regulations for corrosion control, including new requirements for pipe coating assessments, protective coating strength, P&M measures, and additional mitigation of stray current (also referred to as interference current). PHMSA also proposed changes regarding gas stream monitoring program requirements to mitigate internal corrosion. These proposed revisions were made in §§ 192.319, 192.461, 192.465, 192.473, and 192.935(f) and (g) and are discussed more thoroughly in this section. PHMSA also proposed to add a new § 192.478 for the monitoring and mitigation of internal corrosion.

2. Summary of Public Comment

The Coalition to Reroute Nexus, the Michigan Coalition to Protect Public Rights-of-Way, NAPSR, and the PST supported the proposed changes regarding corrosion control and pipeline condition monitoring. Earthworks suggested that PHMSA issue even more stringent requirements given the number of post-Carlsbad incidents that have occurred due to corrosion.[22] The Pipeline Safety Coalition, the Public Service Commission of West Virginia, and the Pennsylvania Public Utility

[21] PHMSA stated, in response to written comments submitted in the docket and discussion during the January 2017 GPAC meeting, that it would in the final rule limit application of the NPRM's proposed management of change amendments at § 192.13(d) to exclude gas distribution and gathering lines. PHMSA notes, however, that (1) PHMSA has undertaken a rulemaking (under RIN 2137–AF53) that will consider extending those or similar requirements to gas distribution pipelines as required by a mandate in section 204 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (Pub. L. 116–260)); and (2) PHMSA may consider extending those or similar requirements to gas gathering lines as PHMSA obtains more information on the safety risks of such pursuant to enhanced reporting requirements codified by PHMSA's Gas Gathering Final Rule.

[22] An incident near Carlsbad, NM, on August 19, 2000, which was caused due to corrosion, killed 12 people and caused nearly $1 million in damage. The incident was a catalyst for PHMSA's IM program requirements for pipelines.

Commission stated that not all gathering pipelines should be exempt from corrosion monitoring.

Some commenters requested clarification regarding whether the proposed provisions were intended to include transmission, distribution, and gathering pipelines. Other commenters provided input on whether gathering pipelines should be included in the corrosion control requirements, especially alternating current voltage gradient (ACVG) and direct current voltage gradient (DCVG) inspections in proposed § 192.461.

During the meeting on June 7, 2017, GPAC committee members questioned whether the corrosion control requirements would apply to gathering lines—the presumption among the majority of the members was that the requirements were not intended to include gathering or distribution lines. The committee provided other feedback specific to the applicability and implementation of specific corrosion topic areas, which are discussed in the applicable sections below.

3. PHMSA Response

PHMSA has considered the comments received regarding the applicability of the proposed corrosion control requirements. PHMSA stated at the June 2017 GPAC meetings, in response to comments received on the NPRM and the discussions during the GPAC meeting, that it would in the final rule exclude gathering and distribution pipelines from the NPRM's proposed requirements in subpart I related to corrosion control. Accordingly, PHMSA has revised § 192.9 to exempt gathering lines from several of these requirements. PHMSA, however, may consider expanding this provision to gathering lines in the future. Comments on the specific provisions proposed for corrosion control are addressed in the following sections.

As to commenters requesting the regulations be made even more strict than proposed, PHMSA notes that changes more stringent than those proposed would require further notice. PHMSA believes that currently, there is also not sufficient data to justify more stringent changes. PHMSA will continue to review all data sources on the subject, including incident and annual reports, and consider more stringent corrosion control safety requirements in a future rulemaking if there is data supporting the need.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

ii. Installation of Pipe in the Ditch and Coating Surveys—§§ 192.319 and 192.461

1. Summary of PHMSA's Proposal

Section 192.319 prescribes requirements for installing pipe in a ditch, including requirements to protect pipe coating from damage during the process. While most operators perform the required high-voltage holiday detection [23] on the pipeline prior to it being placed into the ditch, pipe coating can sometimes be damaged during the handling, lowering, and backfilling process, which can compromise its ability to prevent external corrosion. To address this problem, PHMSA proposed to require that onshore gas transmission pipeline operators perform an above-ground indirect assessment through an ACVG or DCVG survey to identify locations of suspected damage promptly after an operator completes the backfilling process. Per the proposal, operators would remediate any moderate or severe coating damage issues identified by such an assessment, which, was defined as where there are voltage drops of greater than 35 percent for DCVG or 50 dBµV for ACVG.

Section 192.461 prescribes requirements for protective coating systems. PHMSA notes that pipe coating can disbond [24] from the pipe and shield the pipe from CP. The NTSB determined that this was a significant contributing factor in the major crude oil spill that occurred near Marshall, MI, in 2010. As a result, PHMSA determined that additional requirements are needed to specify that coating should not impede cathodic protection. Further, and as discussed above, PHMSA determined that additional requirements are needed so that operators verify that pipeline coating systems for protection against external corrosion have not become compromised or damaged during the installation and backfill process performed during maintenance, repairs, or pipe replacement.[25]

In the NPRM, PHMSA proposed to revise § 192.461(a) to require that pipelines have sufficient coating to protect against damage from being handled. PHMSA also proposed to add § 192.461(f) to require operators to perform an above-ground coating survey within 3 months of placing the pipeline into service and require operators to repair moderate or severe coating damage within 6 months of the assessment.

2. Summary of Public Comment

Stakeholders representing the public, including NAPSR and the PST, generally agreed with and supported the revisions to this section, stating that such requirements would increase safety and were a good step towards reducing the number of incidents that occur due to corrosion. Many commenters stated that ACVG/DCVG surveys are not always feasible and that PHMSA should not limit the tools for performing coating surveys to the two types specified in §§ 192.319 and 192.461(f). For example, INGAA stated that PHMSA did not provide justification for requiring coating surveys, such as ACVG and DCVG, to be used to detect coating issues after construction or after performing a repair or replacement. INGAA further stated that PHMSA should allow operators to use other assessment technologies, such as close interval surveys (CIS) and high-resolution geometry ILI inspection tools, to detect and manage post-construction, post-repair, and post-replacement conditions that contribute to external corrosion.

AGA and AGL Resources (now Southern Company Gas) commented that depth of cover and excessive pavement can make indirect surveys impossible. Further, AGA stated that while conducting post-construction surveys is industry best practice, activities that are not always feasible for operators to complete should not be codified within the regulations.

NACE expressed concern that ACVG and DCVG surveys do not address the stated goal of identifying coatings that impede cathodic protection and objected to setting specific thresholds for these tests. Similarly, INGAA stated that if the requirements for operators to perform coating surveys using ACVG and DCVG are finalized, the proposed voltage drop threshold value in § 192.461(f) should be eliminated.

Industry commenters also stated objections or suggested limitations to the timeframe proposed in § 192.461(f) regarding when these surveys should be performed, stating that the 3-month timeline is inconsistent with the 1-year period allowed to install cathodic protection after the construction of a

[23] ''Holidays'' are essentially holes or gaps in the coating film that exposes the pipeline to corrosion. The inspections of pipeline coating through electronic defect detectors is commonly also referred to as ''jeeping.''

[24] Disbonding is the failure of a coating to adhere to the underlying substance to which it was applied. Specific to pipelines, it is a loss of adhesion between the cathodic coating and the pipe due to a corrosive reaction taking place.

[25] This is similar to a proposal in § 192.319 for new construction.

pipeline in existing § 192.455(a)(2). New Jersey Natural Gas expressed concern that 3 months may not be adequate both to procure qualified personnel and to perform these surveys and have a fully mature cathodic protection system to perform a successful coating assessment. NAPSR believed that, unless there was a technical reason for the 3-month deadline for the surveys, the timeline might be too conservative due to service procurement and seasonal conditions. Therefore, they recommended extending the assessment deadline.

API and Enterprise Products commented that PHMSA does not provide any supporting evidence that backfilling a ditch for an onshore transmission pipeline is, or has been, an issue meriting the need for ACVG or DCVG surveys to assess coating integrity. Further, API and Southern California Gas Company stated that § 192.319(a) already requires all operators of transmission gas pipelines to ''protect the pipe coating from damage,'' either in initial installation, or any time the pipe is exposed and backfill material is added. Therefore, the proposed provisions may be duplicative with § 192.461.

At the GPAC meeting on June 6 and 7, 2017, committee members representing the industry echoed many of the comments received, noting also that ACVG and DCVG surveys may not address issues related to coatings impeding CP. Additionally, some of these members noted that coating surveys are not always feasible, and that PHMSA should not limit the tools for performing such surveys. Further, several GPAC members representing the industry suggested that PHMSA should not set specific repair thresholds in the regulations, and that the provisions do not align with current NACE standards.[26] Certain committee members also recommended applying a greater-than-1000-feet standard for this provision, which would match a proposed requirement for external corrosion control under § 192.461 and thought that the timeline for the above-ground coating survey should be extended from 3 months to 1 year to synchronize with current CP installation requirements. The committee also suggested PHMSA clarify the applicability of these provisions is limited to transmission pipelines.

Therefore, the committee voted 10–0 that these provisions proposed at §§ 192.319 and 192.461 were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) raised the repair threshold from ''moderate'' to ''severe'' indications, (2) modified the requirements to apply to segments greater than 1,000 feet in length to be consistent with other similar corrosion control requirements, (3) extended the assessment and remediation timeframe to 6 months after a pipeline is placed into service and made allowances for delayed permitting, (4) adjusted the recordkeeping requirements so that operators would be required to make and retain for the life of the pipeline records documenting indirect assessment findings and remedial actions, and (5) provided flexibility for the use of alternative technology unless the agency objected.

3. PHMSA Response

Operators have historically assumed that coating is functioning as intended after construction. However, the NTSB report on the Enbridge crude oil accident near Marshall, MI, identified shielded CP due to disbonded coating as being a contributing cause of the failure. Whenever an operator backfills a pipeline, there is the potential for coating damage. PHMSA believes that conducting coating surveys after backfill is a reasonable and reliable way for operators to identify coating damage inflicted during the construction process before significant corrosion occurs. This is a means for an operator to confirm, after pipeline construction or replacement, that the pipe coating is not compromised and is functioning as intended.

PHMSA believes that ACVG/DCVG surveys are currently the best and most reliable means of detecting coating damage following construction, as opposed to a CIS survey, which is a complementary survey employed to assess the performance of CP systems. However, PHMSA desires to promote the development of new technologies and methods and acknowledges that other technology could be used for performing coating assessments. Therefore, in this final rule, PHMSA is allowing an operator to notify PHMSA of the intent to use other technology, which it may use unless an objection is received, as was recommended by the GPAC. PHMSA's review of such notification would evaluate whether an operator has demonstrated that the ''other technology'' provides equivalent protection to public safety and the environment compared the existing technologies contemplated by this final rule. As a part of its evaluation, PHMSA considers whether there are technical papers from standard developing organizations that support the use of the new technology, as well as any research that has been conducted on that technology and any usage of the technology in other industries and non-regulated pipelines.

PHMSA disagrees that the voltage drop threshold value used as the remediation criterion should be eliminated from the regulation but does agree that the values in the proposed revisions to §§ 192.319 and 192.461 in the NPRM were conservative as they would indicate ''moderate'' coating damage. Therefore, in this final rule and as recommended by the GPAC, PHMSA is specifying the voltage drop threshold value associated with a ''severe'' indication of coating damage as recommended by GPAC.

As recommended by the GPAC, PHMSA is persuaded that the 3-month proposed timeline may not be practical in all situations and has modified the final rule to allow operators up to 6 months after the pipeline is placed into service to complete the necessary assessments and remediation (with allowance for time required to obtain permits, if required). PHMSA has also included a requirement for the associated recordkeeping requirements of these provisions that includes the editorial changes recommended by the GPAC; specifically, that operators must make and retain for the life of the pipeline records documenting the indirect assessment findings and remedial actions.

PHMSA also modified both sections to apply to segments greater than 1,000 feet in length to be consistent with other corrosion control requirements that were similarly altered in this final rule. PHMSA notes that the application of these requirements to segments greater than 1,000 feet in length is also consistent with conditions that have been applied in several special permit applications.

As a part of the requirements for these sections, PHMSA has provided in the regulatory text that the applicable coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.[27] These might include crossings of major interstates or rivers. An operator must document, in accordance with a technically proven

[26] When the ANPRM was being developed, NACE did have standards for ACVG/DCVG surveys. Since the development of this final rule, NACE has subsequently revised those standards, and there is no longer a standard for these surveys.

[27] For example, coating surveys could require drilling holes in roadways, or digging up pipe—each of which entail their own risks to public safety and the environment. Some of the pipelines that would be surveyed could either be cased or have thick-walls, further complicating efforts to conduct coating surveys.

analysis, any decision made not to perform such a coating survey.

As noted before, PHMSA did not intend for these provisions to apply to gathering or distribution pipelines, and it has clarified the applicability of these provisions to transmission lines only. However, PHMSA may expand the application of these provisions in a future rulemaking.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

iii. Interference Surveys—§ 192.473

1. Summary of PHMSA's Proposal

Interference currents occur when metallic structures pick up a stray electrical current from elsewhere and discharge the current, thereby causing corrosion. These currents can negate the effectiveness of cathodic protection systems. The sources of stray current problems are commonplace; they can result from other underground facilities, such as the cathodic protection systems from crossing or parallel pipelines, light rail systems, commuter train systems, high-voltage alternating current (HVAC) electrical lines, or other sources of electrical energy in proximity to the pipeline. Stray current corrosion is electrochemical corrosion that occurs when potential differences between a high-conductivity steel pipeline and lower-conductivity environments causes the stray current to flow through the pipe and create a corrosion cell. If stray current or interference issues are not remediated, accelerated corrosion could occur and potentially result in a leak or rupture. Section 192.473 prescribes general requirements to minimize the detrimental effects of interference currents. However, specific requirements to monitor and mitigate detrimental interference currents have not been prescribed in subpart I of part 192. Therefore, in the NPRM, PHMSA proposed to explicitly require operators to conduct interference surveys and remediate adverse conditions in a timely manner. Specifically, PHMSA proposed to amend § 192.473 to require that an operator's program include interference surveys to detect the presence of interference currents and take remedial actions within 6 months of completing the survey. Additionally, PHMSA proposed to require in § 192.473 that operators perform periodic interference surveys whenever needed.

2. Summary of Public Comment

Generally, stakeholders representing the public agreed with and supported the revisions to this section, noting that the requirements, as proposed, could help reduce the number of pipeline incidents caused by corrosion. Numerous trade associations and pipeline companies were concerned about the proposed requirements for interference surveys under § 192.473. Commenters, including Atmos Energy Corporation and AGA, expressed doubt regarding the ability of individual operators to obtain the necessary information from electric transmission providers. APGA and INGAA urged PHMSA to limit this new requirement to specific transmission lines, such as those pipelines subject to the threat of stray electric current. Commenters, including INGAA, also stated that the provisions should allow for the phased-in implementation of remediation measures and provided timeframes from 12 to 18 months. Some commenters suggested a lengthened implementation period for this requirement due to the potential difficulties in obtaining the proper permits.

At the GPAC meeting on June 7, 2017, certain committee members believed that these requirements should apply only to lines that are subject to stray current risks and noted that interference surveys might not be feasible depending on the information operators can obtain from electricity transmission companies. Committee members also suggested a phased-in compliance period between 12 and 18 months for these requirements, and noted, similarly to the proposed external corrosion provisions, that the remediation period did not account for activities like obtaining the necessary permits. There was also extensive discussion at the meeting regarding PHMSA's proposed use of the word ''significant'' in context of the level of corrosion that would need to be remediated, with several committee members suggesting that phrase be tied to a numeric threshold for easier compliance. The committee also discussed, at length, what PHMSA's expectation for a remediation ''plan'' is and what the necessary paper trail would look like for compliance.

After discussion, the committee voted 9–0 that the provisions for external corrosion interference currents are technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that the surveys are required for lines subject to stray currents and updated the remediation timeframe to require operators create a remediation procedure and apply for necessary permits within 6 months and complete remediation activities within 12 months with allowances for delayed permitting. The committee also specifically recommended that PHMSA clarify that operators must take remedial action when the interference is at a level that could cause significant corrosion as being 100 amps per meter squared, or if it impedes the safe operating pressure of the pipeline, or if it may cause a condition that would adversely affect the environment or the public.

3. PHMSA Response

PHMSA agrees with commenters that every pipeline segment is not equally subject to stray current. Therefore, in this final rule, PHMSA is modifying § 192.473 as recommended by the GPAC to clarify that interference surveys are required when electric potential monitoring indicates a significant increase in stray current, or new potential stray current sources are introduced. Additionally, PHMSA recognizes the need for objective remediation criteria and has included the criteria recommended by the GPAC, specifically ''greater than or equal to 100 amps per meter squared or if it impedes the safe operation of a pipeline or may cause a condition that would adversely impact the environment or the public.'' PHMSA has also revised this final rule to establish a remediation timeframe of 15 months, with allowance for delayed permitting, as recommended by the GPAC.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

iv. Internal Corrosion—§ 192.478

1. Summary of PHMSA's Proposal

Section 192.477 prescribes requirements to monitor internal corrosion by coupon testing or other means if corrosive gas is being transported. However, the regulation is silent on standards for determining whether corrosive gas is being transported or regarding any changes occurring that could introduce corrosive contaminants in the gas stream. The existing regulations also do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system changes, changing gas supply, abnormal conditions, or other changes. This could result in pipelines that are not monitored for internal corrosion because an initial assessment did not identify the presence of corrosive gas.

As such, PHMSA determined that additional requirements are needed to ensure that operators effectively monitor gas stream quality to identify if and when corrosive gas is being transported and to mitigate deleterious gas stream constituents such as contaminants or

liquids. In the NPRM, PHMSA proposed to add a new § 192.478 to require onshore gas transmission pipeline operators monitor for deleterious gas stream constituents and evaluate gas monitoring data quarterly. The proposed § 192.478 would also add a requirement for onshore gas transmission pipeline operators to review their internal corrosion monitoring and mitigation program semi-annually and adjust the program as necessary to mitigate the presence of deleterious gas stream constituents. These requirements would be in addition to the existing requirements to check coupons or perform other measures to monitor for the presence of internal corrosion when transporting a known corrosive gas.

2. Summary of Public Comment

NAPSR generally agreed with and supported the addition of this section. They did note, however, that PHMSA should consider the applicability of these requirements to pipelines that are transporting dry, tariff-quality gas. The PST noted that these proposed requirements in this section provided an enforceable mechanism to hold operators accountable for future incidents caused by internal corrosion.

Multiple commenters considered the proposed changes to requirements for internal corrosion control in § 192.478 to be overly prescriptive, particularly regarding gas monitoring and the list of corrosive constituents. INGAA stated that transmission operators are already taking comprehensive steps to address internal corrosion under subparts I and O of part 192 and that proposed § 192.478 should be eliminated for this reason. Atmos Energy Corporation and INGAA asserted that the internal corrosion monitoring timeline proposed in § 192.478(d) is unreasonable and too frequent, particularly for pipeline systems that are not susceptible to internal corrosion. They further stated that mitigation of internal corrosion is necessary only if a pipeline is transporting, or has the potential to transport, corrosive gas. At the GPAC meeting on June 6, 2017, committee members representing the industry supported those comments made by Atmos Energy Corporation and INGAA.

Commenters at the GPAC meeting, including committee members, noted that some distribution operators rely on upstream transmission pipeline gas suppliers to monitor gas quality and do not own any gas monitoring equipment. A committee member noted that if pipeline operators are getting gas from native sources, gathering lines, or underground storage fields, it might be necessary to determine the quality of the gas. Another committee member noted that there are tariffs that prevent certain quantities of constituents that could be internally corrosive from entering a transmission system. That commenter also noted that operators continually monitor for internal corrosion on pipelines transporting tariff-quality gas as a part of IM.

GPAC members also noted that PHMSA should consider harmonizing these requirements with the existing corrosion control monitoring requirements, as they appeared to be duplicative in certain areas.

After discussing the provisions, the committee voted 10–0 that the proposed provisions related to internal corrosion were technically feasible, reasonable, cost-effective, and practicable if PHMSA limited the applicability of the requirements to those pipelines that are transporting corrosive gas and provided additional guidance based on the committee discussion; changed the reference from the use of ''gas-quality monitoring equipment'' to ''gas-quality monitoring methods;'' specified types of technologies operators can use to mitigate potentially corrosive gas streams; and changed the frequency of the monitoring and program review requirements from twice per year to once per calendar year, not to exceed 15 months. The committee also specifically recommended deleting language that was duplicative to existing requirements and instead recommended PHMSA cross-reference those existing requirements in this section.

3. PHMSA Response

PHMSA noted during the GPAC meeting, that, in its experience, transmission pipeline operators measure the quality of the gas coming into their transmission systems. Based on the quality of the gas, transmission pipeline operators are paying suppliers for the gas they receive or are receiving money for the gas they deliver. Therefore, PHMSA assumes transmission pipeline operators have monitoring systems for the quality of the gas entering their systems. PHMSA's intent with the proposed revision of this section was to help ensure that operators were getting that data to the necessary people in their organization. For instance, if an organization's accountants are getting gas quality data due to their work with tariffs, the personnel responsible for operations and integrity management should get that data.

Based on the comments received, PHMSA is revising the scope of proposed § 192.478 in this final rule to limit its applicability to the transportation of corrosive gas and is modifying the proposed language in paragraph (b)(1) to specify that operators perform monitoring at points where gas with potentially corrosive contaminants enters the pipeline. To address concerns regarding the monitoring frequency, PHMSA is changing the requirement from twice per year to once per calendar year, not to exceed 15 months. Making such a change is more consistent with the timeframes for similar requirements in the regulations as revised by this rulemaking and implements the recommendation made by the GPAC.

Further, to harmonize this rule with other rule requirements, PHMSA is deleting proposed paragraph (c), since § 192.477 currently requires the monitoring of internal corrosion. To address comments regarding technology, PHMSA revised paragraph (b)(2) to read ''Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling and inhibitor injections.''

There have been instances where operators do transport corrosive gas by pipeline without investigating the possibility of corrosive effect of the gas on its pipeline and taking steps to minimize internal corrosion.[28] This has happened after operators have withdrawn gas from storage facilities (*e.g.,* caverns) where the gas that was injected became corrosive over time because of properties of the storage facilities. Therefore, there can be scenarios where corrosive gas can enter a pipeline system even if the gas being delivered into the upstream system is non-corrosive.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

v. Cathodic Protection—§ 192.465 & Appendix D

1. Summary of PHMSA's Proposal

Appendix D to part 192, ''Criteria for Cathodic Protection and Determination of Measurements,'' which is referenced in § 192.465(f), specifies requirements for CP of steel, cast iron, and ductile pipelines. Appendix D has not been updated since 1971. The NPRM

[28] In the Matter of Transcontinental Gas Pipe Line Company, LLC, CPF 1–2018–1005, available at *https://primis.phmsa.dot.gov/comm/reports/enforce/documents/120181005/120181005_Final%20Order_06192019.pdf* (last visited March 27, 2020). On December 12, 2016, Transcontinental Gas Pipe Line Company reported an explosion and fire that severely damaged a portion of one of its facilities and station piping, resulting in an estimated $15 million in damage. The root cause was determined to be internal corrosion caused by salt water produced from a storage field during gas withdrawal.

proposed to update appendix D by eliminating outdated guidance on CP and the interpretation of voltage measurement to better align with current standards and PHMSA's understanding of current industry practice.

Section 192.465 currently prescribes that operators monitor CP and take prompt remedial action to correct deficiencies indicated by the monitoring. The provisions in § 192.465 do not specify the remedial actions required to correct deficiencies and do not define ''prompt.'' To address this gap, the NPRM proposed to amend § 192.465(d) to require that operators must complete remedial action promptly, but no later than the next monitoring interval specified in § 192.465, or within 1 year, whichever is less. Additionally, new paragraph (f) proposed to add requirements for onshore gas transmission pipeline operators to perform CIS if annual test station readings indicate CP is below the level of protection required in subpart I. Unless it is impractical to do so, PHMSA proposed to require that operators complete CIS with the protective current interrupted. Whereas ACVG and DCVG are performed at the time of construction, before electrical current is on the pipe for CP, a CIS requires the pipe to be in the ground with the rectifiers installed. A CIS will discover areas of low current where CP might be weakened and can discover additional construction, operational or environmental damage along the pipeline when performed as a post-construction task. The NPRM's proposed revisions to § 192.465 would also require each operator to take remedial action to correct any deficiencies indicated by the CIS.

2. Summary of Public Comment

NAPSR and the PST generally agreed with and supported the revisions to § 192.465. NAPSR believed that the inclusion of a timeframe for operators to perform CIS and perform subsequent mitigation measures would increase pipeline safety but noted that PHMSA should provide further guidance on the intervals at which operators should perform the surveys. Both PST and NAPSR supported the revisions to appendix D.

Several industry entities commented on the proposed revisions to appendix D to part 192. INGAA stated that the proposed remaining criteria in appendix D for determining the adequacy of cathodic protection are too narrow, and that all industry standards provide for additional methods of assessing voltage drop. These commenters recommended that PHMSA follow the applicable paragraphs of NACE Standard Practice SP0169. Enterprise noted that appendix D should be consistent with § 195.571, which outlines the criteria that hazardous liquid pipeline operators must use when determining the adequacy of cathodic protection.

Commenters stated that the proposed changes to appendix D, as written, would apply to distribution pipelines as well as transmission pipelines and expressed concern that PHMSA has offered neither justification nor an estimate of the impact on distribution systems. These commenters requested that PHMSA clarify that the proposed changes to appendix D apply only to transmission pipelines.

Commenters, including committee members representing the industry during the meeting on June 6, 2017, stated that PHMSA should amend § 192.465 to include a more realistic timeframe for remedial action, specifically noting that the timeframe for remediation does not account for difficulties in obtaining the necessary permits. Additionally, commenters and GPAC committee members stated this provision could lead to unnecessary and costly work, as there are various situations that can produce a low CP reading that do not require CIS for the identification of the root cause. Those commenters stated there are certain conditions that do not require CIS and recommended allowing operators to identify, troubleshoot, and remediate these certain conditions on their own without the need to conduct CIS.

Further, GPAC members representing the industry disagreed with PHMSA's proposed revisions to the appendix D criteria for determining the adequacy of cathodic protection. Like their commentary on other provisions, these committee members also noted that the impact of these changes to distribution pipelines was not justified or analyzed, and therefore, distribution pipelines should be exempt from the proposed requirements.

Following their discussion, the committee voted 10–0 that the provisions related to the CP of steel, cast iron, and ductile pipelines were technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that the new requirements in § 192.465(d) only apply to gas transmission pipelines and withdrew the proposed revisions to appendix D. The committee also recommended that PHMSA address situations where CIS may not be an effective response by instead requiring operators investigate and mitigate any non-systemic or location-specific causes of corrosion and require CIS if operators need to address systemic causes of corrosion. Additionally, the committee recommended PHMSA address its comments regarding the timeframe by which the proposed provisions would need to be completed by requiring operators make a remedial action plan and apply for any necessary permits within 6 months and finish the remedial action within 1 calendar year, not to exceed 15 months, or as soon as practicable once the operator obtains the necessary permits.

3. PHMSA Response

PHMSA intended that the amendments proposed in the NPRM would apply only to transmission pipelines and has, in this final rule, added the phrase ''onshore gas transmission pipelines'' to § 192.465(d)(1) of to clarify that limitation. PHMSA will consider expanding application beyond onshore gas transmission pipelines in the future. PHMSA believes that modifying the timeline for remediation is appropriate, and therefore, is requiring operators develop a remedial action plan and apply for the necessary permits within 6 months of the inspection, with the completion of remediation activities to be completed prior to the next monitoring interval or within 1 year, not to exceed 15 months. Like the previous section, such a change is consistent with both the GPAC recommendation on the issue and the timeframes for the related regulations in this final rule. PHMSA understands that, in almost all cases where an operator performs an excavation of 1,000 feet or more, that excavation will probably require some permits. An operator should obtain such permits in a manner to allow the performance of coating surveys and any necessary repairs to the coating.

In the NPRM, PHMSA proposed to update appendix D but did not intend to introduce any new requirements. PHMSA agrees with certain commenters that the proposed revisions could have unintended consequences by creating potential tension with analogous cathodic protection evaluation criteria in NACE Standard Practice SP0169 and § 195.571 governing hazardous liquid lines (which section incorporates NACE Standard Practice SP0169 by reference). However, as PHMSA did not propose incorporation by reference of NACE Standard Practice SP0169 in appendix D, PHMSA is withdrawing the proposed changes to appendix D. PHMSA will continue to examine appropriate evaluation criteria for catholic protection of gas transmission pipelines and may pursue future rulemaking on

this topic. These changes to the final rule for CP requirements are in accordance with the GPAC recommendations.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

vi. P&M Measures—§ 192.935(f) & (g)

1. Summary of PHMSA's Proposal

Currently, the gas transmission IM provisions do not explicitly address additional P&M measures for the threats of external and internal corrosion. For the same reasons that apply to the proposed changes for general corrosion control as discussed above, PHMSA proposed to address these gaps for HCAs. PHMSA determined that additional P&M measures are needed in § 192.935(f) and (g) to assure that public safety is enhanced in HCAs through additional protections from the time-dependent threats of internal and external corrosion. Specifically, PHMSA proposed to add § 192.935(f) and (g), which would require that operators enhance their corrosion control programs in HCAs to provide additional corrosion protections in addition to the proposed standards in subpart I. Under proposed § 192.935(f), operators would be required to enhance their internal corrosion management programs by performing mitigative actions if deleterious gas stream constituents are being transported and through performing semi-annual reviews of their programs.

Regarding the internal corrosion provisions discussed earlier in this document, § 192.477 prescribes requirements to monitor internal corrosion by coupon testing or other means if corrosive gas is being transported. However, the existing regulations do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system changes, changing gas supply, abnormal conditions, or other changes. This could result in pipelines that are not monitored for internal corrosion because an operator's initial assessment did not identify the presence of corrosive gas. To provide additional protections for HCAs in addition to the standards proposed in subpart I, PHMSA proposed that § 192.935(f) would require operators use specific gas quality monitoring equipment for HCA segments, including but not limited to, a moisture analyzer, chromatograph, samplers for carbon dioxide, and samplers for hydrogen sulfide. The proposed provisions would also require operators sample at a certain frequency, use cleaning pigs to sample accumulated liquids and solids, and use corrosion inhibitors when corrosive constituents are present. PHMSA also proposed the maximum amounts of carbon dioxide, moisture content, and hydrogen sulfide that would require operator action.

Under proposed § 192.935(g), operators would also be required to enhance their external corrosion management programs, including controlling both alternating and direct electrical interference currents, confirming external corrosion control through indirect assessment, and controlling external corrosion through CP.

As described in the discussion on interference surveys above, interference currents can negate the effectiveness of CP systems. Section 192.473 prescribes general requirements to minimize the detrimental effects of interference currents. In the NPRM, PHMSA proposed to amend § 192.473 to require that an operator's corrosion control program include interference surveys to detect the presence of interference currents and require the operator take remedial actions within 6 months of completing the survey. In HCAs, PHMSA proposed additional prescriptive requirements in § 192.935(g) to afford extra protections for HCAs, including a maximum interval of 7 years for an operator to perform interference surveys; more specificity regarding the survey performance, including technical acceptance criteria; and a requirement that pipe-to-soil test stations be located at half-mile intervals within each HCA segment with at least one station in each HCA, if practicable.

Lastly, PHMSA proposed to make conforming edits to appendix E, which provides guidance for P&M measures for HCA segments subject to subpart O. PHMSA proposed to accommodate the proposed revised definition for ''electrical survey'' by replacing that term with ''indirect assessment'' to accommodate other techniques in addition to CIS.

2. Summary of Public Comment

NAPSR and the PST agreed with and supported the proposed changes to the P&M measures for addressing internal and external corrosion in HCAs and suggested strengthening the proposed provisions further.

While trade associations and individual operators supported certain aspects of the proposed provisions covering the P&M measures addressing external corrosion and internal corrosion in HCAs, these commenters objected to the specific requirements in § 192.935. Many of these commenters stated a preference for allowing operators the flexibility to implement corrosion control based on their own judgment of the severity of the threat. In general, many industry commenters stated that individual sections of the proposed provisions were too broad and prescriptive, and pipeline operators would incur greater costs without justified benefit. Further, they stated that the monitoring frequency of twice per year was too frequent. Some commenters recommended that PHMSA reference ASME standards for implementing P&M measures, and other commenters stated concern that some of the proposed provisions are not consistent with NACE standards.

Many commenters objected to several of the proposed aspects of internal corrosion control, such as the identification of threats, monitoring, and filtering, and these commenters stated that operators should have flexibility in implementing P&M measures. For example, INGAA opposed the proposed requirement in § 192.935(f) that requires operators to install continuous gas quality monitoring equipment at all points in which gas with potentially deleterious contaminants enters the pipeline. INGAA recommended that § 192.935(f) apply only to pipeline segments with a history of internal corrosion and stated that this would be consistent with the required risk analysis that operators perform to determine whether P&M measures are necessary. Similarly, Atmos Energy recommended that gas sources be monitored only at those sources suspected, in the judgment of the operator, of having deleterious gas stream constituents, and that such monitoring can be performed in real-time or periodically. INGAA stated that PHMSA should modify proposed § 192.935(g) to require that operators conduct periodic indirect inspections only where a pipeline segment has a known history of corrosion.

During the GPAC meeting on June 6, 2017, committee members representing the industry reiterated that § 192.935(f) and (g) were too broad and prescriptive and should not apply to every HCA pipeline segment indiscriminately. These members, echoing comments made by INGAA, stated that operators should use their risk assessments to be used to determine which specific P&M measures are needed in accordance with the current IM approach.

The committee also suggested that PHMSA should reference specific ASME standards for P&M measures and ensure they are consistent with NACE

standards. Members representing the public suggested PHMSA review the proposed changes throughout subpart I and ensure that they would be as enforceable as the proposed P&M measures if the P&M measures were to be deleted. Members also discussed the fact that distribution operators do not always have gas monitoring equipment for their lines, as they depend on the suppliers to monitor the gas quality.

Following the discussion, the committee voted 9–1 (with a representative from PST dissenting) that the proposed rule, regarding the provisions for P&M measures for internal and external corrosion, were technically feasible, reasonable, cost-effective, and practicable if PHMSA withdrew the specific provisions discussed in § 192.935(f) and (g) and appendix E, as the requirements would have been duplicative with subpart I.

3. PHMSA Response

PHMSA noted during the GPAC meeting that it was persuaded by commenters that the changes it is making to the general corrosion control requirements in subpart I in this final rule are sufficient and that the additional regulations proposed in § 192.935(f) and (g) and appendix E were duplicative. The proposed changes to subpart I that PHMSA is finalizing in this rulemaking apply to pipelines in both HCAs and non-HCAs, and they were similar to the P&M measures that PHMSA was proposing regarding corrosion control in HCAs specifically. Therefore, PHMSA believes that the changes to subpart I in this rule provide the safety that the proposed changes at § 192.935(f) and (g) intended to provide. The proposed changes to appendix E incorporated the proposed definition for ''electrical survey'' and did not contain further substantive changes. After considering those comments, and as recommended by the GPAC, PHMSA is withdrawing all the proposed changes to § 192.935(f) and (g) and appendix E.

D. Inspections Following Extreme Weather Events—§ 192.613

1. Summary of PHMSA's Proposal

Weather events and natural disasters that can cause river scour, soil subsidence or ground movement may subject pipelines to additional external loads, which could cause a pipeline to fail. These conditions can pose a threat to the integrity of pipeline facilities if those threats are not promptly identified and mitigated. While the existing regulations provide for design standards that consider the load that may be imposed by geological forces, weather events and natural disasters can quickly impact the safe operation of a pipeline and have severe consequences if not mitigated and remediated as quickly as possible.

In the NPRM, PHMSA proposed revising § 192.613 to require that an operator inspect all potentially affected pipeline facilities after an extreme weather event to help ensure that no conditions exist that could adversely affect the safe operation of that pipeline. The operator would be required to consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the inspection required. The NPRM's proposed revisions to § 192.613 also provided that the initial inspection must occur within 72 hours after the cessation of the event, defined as the point in time when the affected area can be safely accessed by available personnel and equipment required to perform the inspection. If an operator finds an adverse condition, the NPRM' s proposed revisions to § 192.613 would require an operator to take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained because of performing the inspection.

2. Summary of Public Comment

The PST, NAPSR, and EnLink Midstream supported the proposed amendments to § 192.613, with many other stakeholders supporting the intent of the proposed provisions but requesting further clarification on some of the terms used within the proposal.

Some commenters expressed concern with the broad requirements of an ''inspection'' and requested PHMSA clarify what an inspection following an extreme weather event would entail. Additionally, these stakeholders stated that the proposed definition of an extreme weather event was vague and requested clarification. INGAA stated that operators are already required to have procedures to ensure a prompt and effective response to emergency conditions through § 192.615 and suggested that to avoid duplicative regulation, PHMSA should instead modify § 192.615(a)(3) to incorporate additional specificity on weather events that may trigger a response.

Many commenters objected to the proposed timeframe, stating that the 72-hour requirement listed in the rule could be problematic. Commenters stated that PHMSA should allow operators to determine when an impacted area can be safely accessed, and that pipeline operators are best positioned to evaluate the balance between the safety and the need for inspections to ensure continued safe operation of their systems. INGAA stated that the 72-hour requirement should either be replaced with a more general statement such as ''as soon as practicable,'' or that PHMSA should create a process to request an exception to the requirement. Louisiana Mid-Continent Oil and Gas Associations stated that extreme weather events vary significantly by region and commented that not all local geography and extreme weather events are the same. They further stated that the 72-hour deadline for inspection may be too prescriptive depending on the extreme weather event. They stated that because Louisiana is subjected to many unusual extraordinary events, such as spillway openings, high/low river flows, and rainwater flooding, PHMSA should clarify what ''other events'' means and how the cessation of an event is determined.

At the GPAC meeting of January 12, 2017, members noted concerns with the provisions as proposed but voted 12–0 that the provisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA modified the proposed rule to clarify that the timing for this provision is to begin after the operator has made a reasonable determination that the area is safe, clarify in the preamble that operators are encouraged to consult with pipeline safety and public safety officials in order to make such determinations, delete the phrase ''whichever is sooner'' at the end of § 192.613(c)(2), and change the word ''infrastructure'' to ''facilities.''

3. PHMSA Response

PHMSA agrees that an operator's ability to inspect a pipeline facility following an extreme weather event may vary greatly depending on the type of extreme weather event that has taken place and the specific location of the event. The NPRM's proposed revisions to § 192.613 would require operators to inspect its pipeline facilities after the cessation of an extreme weather event. Cessation of the event was defined as the point of time when the affected area could be safely accessed by the personnel and equipment, including availability of personnel and equipment, required to perform the inspection. However, in consideration of the comments received, PHMSA is persuaded that additional clarification is warranted and that 72 hours after the cessation of the event may not be enough time in all cases for operator personnel and equipment to assess and inspect a pipeline safely.

Therefore, as recommended by the GPAC, PHMSA has modified this final rule to require an operator perform an initial inspection 72 hours after the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the necessary personnel and equipment required to perform such an inspection are available. PHMSA encourages operators to consult with pipeline and public safety officials, including the appropriate PHMSA regional office, when making these determinations. If an operator is unable to commence the inspection in the 72-hour timeframe due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable.

If an operator finds an adverse condition, the operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained from the inspection. Such actions might include, but are not limited to:

• Reducing the operating pressure or shutting down the pipeline;
• Isolating pipelines in affected areas and performing ''stand up'' leak tests;
• Modifying, repairing, or replacing any damaged pipeline facilities;
• Preventing, mitigating, or eliminating any unsafe conditions in the pipeline rights-of-way;
• Performing additional patrols, depth of cover surveys and adding cover over the pipeline, ILI or hydrostatic tests, or other inspections to confirm the condition of the pipeline and identify any imminent threats to the pipeline;
• Implementing emergency response activities with Federal, State, or local personnel; and
• Notifying affected communities of the steps that can be taken to ensure public safety.

PHMSA would not expect operators to comply with these provisions for weather or other disruptive events when, considering the physical characteristics, operating conditions, location, and prior history of the affected system, the event would not be expected to impact the integrity of the pipeline. For example, extreme weather events would not include rain events that do not exceed the high-water banks of the rivers, streams or beaches in proximity to the pipeline; rain events that do not result in a landslide in the area of the pipeline; storms that do not produce winds at tropical storm or hurricane level velocities; or earthquakes that do not cause soil movement in the area of the pipeline.

PHMSA is also modifying § 192.613(c) introductory text and (c)(1) as the GPAC recommended, by removing the phrase ''whichever is sooner'' and replacing the term ''infrastructure'' with ''facilities.'' As discussed during the GPAC meeting, ''pipeline facilities'' is a defined term at § 192.3, and the use of that term will likely provide additional clarity.

E. Strengthening Requirements for Assessment Methods—§§ 192.923(b) & (c), 192.927, 192.929

i. Internal Corrosion Direct Assessment (ICDA)—§§ 192.923(b) & 192.927

1. Summary of PHMSA's Proposal

The current regulations do not specify the quality and effectiveness of ICDA. NACE International submitted a petition for rulemaking on February 11, 2009, requesting that PHMSA address this issue. In the NPRM, PHMSA proposed amendments to §§ 192.923(b) and 192.927 to incorporate by reference NACE SP0206–2006 and further supplement the NACE standard to address issues observed by PHMSA.

For indirect inspections, PHMSA proposed to require that operators use pipeline-specific data, exclusively in performing an indirect inspection, and that the use of assumed pipeline or operational data would be prohibited. PHMSA also proposed operators be required to consider the accuracy, reliability, and uncertainty of data used to make calculations regarding the critical inclination angle of liquid holdup and the inclination profile of pipelines. Further, PHMSA proposed that operators be required to select locations for direct examination and establish the extent of pipe exposure needed, to explicitly account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

For detailed examinations as defined in NACE SP0206–2006, PHMSA proposed to require that operators identify a minimum of two locations for excavation within each covered segment associated with the ICDA Region and perform a detailed examination for internal corrosion at each location using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques. One required location would be the low point within the covered segment nearest to the beginning of the ICDA Region. The second required location would be near the end of the ICDA Region within the covered segment. If corrosion was found at any location, the operator would be required to evaluate the severity of the defect, expand the detailed examination program to determine all locations that have internal corrosion within the ICDA region, and expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) with similar characteristics to the ICDA Region in the operator's pipeline system.

For post-assessment evaluation and monitoring, PHMSA proposed to require that operators evaluate the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those currently specified in the regulations at § 192.939. PHMSA also proposed to require that operators validate their flow modeling calculations by comparing locations of discovered internal corrosion with locations predicted by the model. Additionally, PHMSA proposed to require that operators continually monitor each ICDA Region that contains a covered segment where internal corrosion was identified and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products.

Finally, PHMSA proposed to require that operators include in their plans the criteria used in making key decisions in implementing each stage of the ICDA process and provisions that the analysis be carried out on the entire pipeline in which covered segments are present.

2. Summary of Public Comment

NAPSR expressed its agreement with, and support for, the proposed revisions to §§ 192.923(b) and 192.927. Multiple pipeline operators and industry trade associations commented that the proposed provisions should simply incorporate the NACE standard by reference, and should not exceed those established industry standards, be rigidly prescriptive, or otherwise be mandatory. PG&E, commenting on the incorporation of standards by reference, requested PHMSA replace the phrase ''as required by'' with ''in accordance with'' so that operators can meet the substantial requirement but have flexibility in the implementation of that requirement if the industry publishes new techniques to perform ICDA. NACE International expressed its belief that, as described in NACE SP0206–2006, ICDA is an acceptable standalone methodology for assessing pipeline integrity.

Atmos Energy commented that the proposed mandated monitoring for all ICDA regions would be potentially excessive and recommended that PHMSA delete the proposed language and restore the current language at

§ 192.927(c)(4)(ii).[29] Another commenter recommended that PHMSA remove the proposed notification requirement prior to an operator performing an ICDA, noting that operators currently provide this information as part of other annual reporting.

At the GPAC meeting on December 15, 2017, the GPAC committee voted, 13–0, to revise §§ 192.923(b)(2) and (3) and 192.927 according to the recommendations by PHMSA staff at the meeting, which included supplementing the NACE standard with additional requirements to address specific issues that could adversely affect ICDA results.

3. PHMSA Response

PHMSA believes that it is appropriate to address ICDA by incorporating by reference the NACE standard and supplementing it with additional requirements pertaining to indirect inspections (a step in the NACE standard's ICDA process to help in determining where direct assessments need to be made), detailed examinations, and post-assessments. For indirect inspections, PHMSA has implemented additional requirements regarding the data an operator must use and accounting for uncertainties in that data. Where an indirect inspection demonstrates that detailed examinations are needed, PHMSA is expanding the examinations that an operator must perform to evaluate for the potential for internal corrosion in all pipeline segments if corrosion is found in the ICDA region. Regarding post-assessments, PHMSA is requiring operators to evaluate the effectiveness of ICDA as an assessment method and determine whether a covered segment should be reassessed more frequently than the intervals specified at § 192.939. Additionally, PHMSA is requiring operators validate the flow modelling calculations they use in the ICDA process as well as continually monitor each ICDA region that contains a covered segment where internal corrosion has been identified.

When the first IM regulations were promulgated in the 2003 IM rule, there was no consensus industry standard for ICDA that could be adapted or incorporated into the regulations to promote better pipeline safety regarding internal corrosion. Incorporating by reference the NACE standard into the regulations would improve pipeline safety because the NACE standard (1) typically requires more direct examinations than the current regulatory requirements; (2) encompasses the entire pipeline segment and requires that all inputs and outputs be evaluated; and (3) is considered by many to be an equivalent or superior indirect inspection model compared to the Gas Technology Institute (GTI) model currently referenced in § 192.927. Its range of applicability with respect to operating pressure is greater than the GTI model, thus allowing the use of ICDA in pipelines with lower operating pressures and higher flow velocities.

The existing requirements in § 192.927 have one aspect that has proven problematic: the definition of regions and requirements for selection of direct examination locations in the regulations are tied to the covered segment. A ''covered segment'' is defined in § 192.903 as ''a segment of gas transmission pipeline located in a high consequence area.'' The terms ''gas'' and ''transmission line'' are defined in § 192.3. Therefore, covered segment boundaries are determined by population density and other consequence factors without regard to the orientation of the pipe and the presence of locations at which corrosive agents may be introduced or may collect and where internal corrosion would most likely be detected (*e.g.,* low spots). Section 192.927 requires that locations selected for excavation and detailed examination be within covered segments, meaning that the locations at which internal corrosion would most likely be detected may not be examined. Thus, the existing requirements do not always facilitate the discovery of internal corrosion that could affect covered segments. PHMSA is addressing this problem in this final rule by incorporating NACE SP0206–2006 and by expanding the detailed examination program, whenever internal corrosion is discovered, to determine all locations that have internal corrosion within the ICDA region.

PHMSA believes requiring a notification requirement for operators is important so that PHMSA can review the specific proposal to use a standard to assess pipe segments that are explicitly excluded from the scope of the standard. PHMSA has also revised § 192.927(c) to clarify that an operator must conduct the ICDA process ''in accordance with'' the NACE standard to avoid the implication that all non-mandatory recommendations contained in the standard are required.

E. Strengthening Requirements for Assessment Methods—§§ 192.923(b) & (c), 192.927, 192.929

ii. Stress Corrosion Cracking Direct Assessment (SCCDA)—§§ 192.923 & 192.929

1. Summary of PHMSA's Proposal

The current regulations do not specify a number of issues that affect the quality and effectiveness of SCCDA integrity assessments. Specifically, Appendix A3 of ASME/ANSI B31.8S, which is referenced in the regulations, provides some guidance for conducting SCCDA, but the guidance is limited to stress corrosion cracking (SCC) that occurs in high-pH environments. NACE International submitted a petition for rulemaking to PHMSA on February 11, 2009, requesting that PHMSA address this issue by incorporating by reference NACE SP0204–2008, which addresses near-neutral SCC in addition to high-pH SCC. Accordingly, in the NPRM, PHMSA proposed changes to §§ 192.923 and 192.929 to incorporate by reference NACE SP0204–2008 and supplement the NACE standard to address issues observed by PHMSA in the areas of data gathering and integration, indirect inspection, direct examinations, remediation and mitigation, and post-assessments.

PHMSA proposed to require an operator's SCCDA plan to evaluate the effects of a carbonate-bicarbonate environment; the effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments; the effects of variations in applied CP, such as overprotection, CP loss for extended periods, and high negative potentials; the effects of coatings that shield CP when disbonded from the pipe; and other factors that affect the mechanistic properties associated with SCC.

For indirect inspections, PHMSA proposed to require an operator's plan include provisions for conducting at least two above-ground surveys using complementary measurement tools most appropriate for the pipeline segment based on the data gathered.

For direct examinations, PHMSA proposed to require an operator's procedures provide for conducting a minimum of three direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur.

For post-assessments, PHMSA proposed to require that the operator's procedures include the development of a reassessment plan based on the

[29] PHMSA regulations at § 192.927(c)(2) define an ICDA region as a continuous length of pipe (including weld joints), uninterrupted by any significant change in water or flow characteristics, that includes similar physical characteristics or operating history. An ICDA region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline.

susceptibility of the operator's pipe to SCC as well as on the mechanistic behavior of identified cracking.

2. Summary of Public Comment

Multiple commenters supported the proposed changes to § 192.929 for SCCDA. NAPSR expressed its agreement with, and support of, these revisions. Spectra Energy Partners (SEP), which merged with Enbridge in 2017, provided comments in support of the proposed inclusion of explicit requirements for SCCDA. SEP expressed its belief that SCCDA is a diligent, practicable approach for assessments for SCC for cases where the pipeline has not previously experienced an in-service failure caused by SCC and provided specific edits to make the proposed requirements for SCCDA clearer and more practicable. A commenter recommended that the requirements for SCCDA specify that an operator is required to conduct assessments in areas that are most likely to be subject to SCC regardless of HCA designation.

Several other commenters questioned or opposed the proposed changes to § 192.929. Several commenters, including API, expressed their support of NACE standards SP0204–2008 for SCCDA but recommended that PHMSA not exceed those established industry standards and should not make the recommendations within those standards mandatory. NACE International stated it was unaware of any conclusive data regarding overprotection or high-negative potentials as a factor in SCC of pipelines, which is what the NPRM's proposed revisions to § 192.929 suggested. Additionally, NACE International commented that PHMSA went beyond the practices stated in NACE Standard SP0204–2008 by proposing to require a minimum of two above-ground surveys and three direct examinations.

INGAA proposed to clarify the way in which SCCDA can be used as an IM method, asserting that SCCDA is a valid method to assess SCC threats in gas pipeline segments that are susceptible to, but have no history of, SCC.

Other commenters provided specific technical comments regarding these proposed provisions. TransCanada asserted that applying the NACE ''significant SCC'' definition as the threshold for immediate repair is both overly conservative and overly complicated, and they suggested that PHMSA instead adopt the threshold of ''noteworthy'' as defined in ASME STP–PT–011.

Enable Midstream Partners (EMP) agreed that operators should consider the specific factors PHMSA proposed in § 192.929(b)(1) and (4) as part of the data gathering and integration and post-assessment remediation and mitigation process for SCCDA. However, EMP asserted that PHMSA should clarify these sections by including a referenced standard that provides guidance to operators on how they should consider these specific factors. Another commenter stated that PHMSA should include a reference to ASME/ANSI B31.8S, Appendix A3, for susceptibility criteria.

Commenters also suggested that PHMSA allow operators to use sound engineering judgments when calculating the remaining strength of the pipeline segment if the segment is subject to the pipeline material properties and attributes verification requirements of § 192.607 and those requirements have not yet been met.

At the GPAC meeting on December 15, 2017, the committee recommended PHMSA revise the approach proposed in the NPRM by making the changes to these provisions that were recommended by PHMSA staff during the meeting, which were to replace the spike hydrostatic pressure test requirements with a reference to § 192.506(e) to eliminate redundancy; address the gap pertaining to failure pressure calculations when data is not available; codify, as applicable, the expectation that the recommendations within the NACE standard are not mandatory; communicate additional guidance as needed during rule implementation; and consider how to structure the rule to apply results from non-HCAs to HCAs.

3. PHMSA Response

When the first IM rule was promulgated in 2003, there was no NACE standard for SCCDA. Additionally, the requirements pertaining to SCC in ASME/ANSI B31.8S, Appendix B, only applied to pipe susceptible to high pH SCC (*i.e.,* pipelines susceptible to near-neutral SCC were not addressed). Therefore, PHMSA believes that incorporating by reference the NACE standard and supplementing it with additional requirements to address issues it has observed related to data gathering and integration, indirect inspection, direct examinations, remediation and mitigation, and post-assessments, is an appropriate way to address SCCDA.

For data gathering and integration, PHMSA is requiring that operators gather and evaluate data related to SCC at all sites an operator excavates while conducting its pipeline operations where the criteria in NACE SP0204–2008 indicate the potential for SCC. Per this final rule, operators must additionally analyze the effects of a carbonate-bicarbonate environment, cyclic loading conditions, variations in applied CP, the effects of coatings that shield CP when disbonded from the pipe, and other factors that would affect the mechanics of SCC. For indirect inspections, PHMSA is requiring operators conduct at least two above-ground surveys using the measurement tools most appropriate for the pipeline segment based on an evaluation of the collected data. An operator's plan for direct examination must include a minimum of three direct examinations within the SCC segment at the locations where SCC would be most likely to occur. If an operator finds any indication of SCC in a segment, an operator must perform specific mitigation measures. Further, in this final rule, an operator must develop procedures for post-assessments based on the susceptibility of the pipeline segment to SCC as well as the mechanical behavior of identified cracking. Regarding EMP's comment stating that PHMSA should provide guidance to operators on how they should consider specific factors as a part of the data gathering and integration process by referring to a standard incorporated by reference within PHMSA regulations, as well as the comment recommending that PHMSA incorporate a reference to ASME/ANSI B31.8S, Appendix A3, for susceptibility criteria, PHMSA declines to incorporate by reference such standards because it could limit operators from considering all of the factors that they should.

PHMSA also agrees with commenters that referring to § 192.506, *Transmission lines: Spike hydrostatic pressure test,* in § 192.929 is preferred instead of repeating the spike hydrostatic test requirements and has changed this final rule accordingly. PHMSA addressed the comment about determining predicted failure pressure when needed data are not available by referencing § 192.712, which explicitly provides an operator with conservative assumptions and alternatives for material toughness values, material strength, and pipe dimensions and other data, in lieu of documented material properties.

F. Repair Criteria—§§ 192.714, 192.933

PHMSA identified several improvements to the IM repair criteria based on its experience gained since the IM rule became effective in 2004; ongoing research and development, including developments in ASME/ANSI B31.8S; and investigations into recent incidents. In the NPRM, PHMSA

proposed adjustments to the existing repair criteria for anomalies discovered in HCAs and proposed new repair criteria for anomalies found outside of HCAs.[30]

F. Repair Criteria—§§ 192.714, 192.933

i. Repair Criteria in HCAs—§ 192.933

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to add more immediate repair conditions and more 1-year repair conditions for HCA pipeline segments in § 192.933. The specific anomalies and repair schedules for cracks, dents, and corrosion metal loss are discussed in their respective sections below. In certain cases, like for SCC and selective seam weld corrosion anomalies that were new to the repair criteria, PHMSA proposed to require that operators repair ''any indication of'' such anomalies. In other cases, such as for dents, PHMSA did not make significant changes to the existing repair criteria at § 192.933, which require the repair of ''any indication of'' metal loss, cracking, or a stress riser.

2. Summary of Public Comment

Public advocacy groups, including Pipeline Safety Coalition, the PST, and Clean Water for North Carolina, supported the proposed provisions that would strengthen the existing repair criteria at §§ 192.713 (non-HCAs) and 192.933 (HCAs). Additionally, NAPSR and the NTSB supported PHMSA's proposed repair criteria revisions.

There was common agreement from pipeline operators and the industry trade associations that the processes for HCA repairs and non-HCA repairs should be standardized. However, the trade associations and pipeline operators generally believed that the proposed provisions at §§ 192.713 and 192.933 were too prescriptive and would impede operators from performing repairs based on risks. They further stated that the proposed provisions do not take into consideration other factors that operators currently consider when optimizing plans to remediate anomalies, such as historical data, geography, and congestion of the right-of-way.

Some of the commenters representing the industry recommended PHMSA eliminate all references to the words ''any indication of'' within the proposed revisions to §§ 192.713 and 192.933 when applied to anomalies needing repair so that it is the confirmed presence of a condition that requires a repair instead. These commenters stated that requiring operators to repair an ''indication of'' certain anomalies would cause needless repairs and misallocate resources. Spectra Energy stated that PHMSA's annual report data indicates that only one repair is required for every three anomaly investigations, which demonstrates that the existing anomaly response criteria operators have implemented are appropriately conservative.

3. PHMSA Response

Based on PHMSA's annual report data, the number of immediate repairs have remained relatively constant even though the baseline assessment period has concluded. PHMSA understands that this is likely the result of operators deferring repair of non-immediate conditions until the defect progresses into an immediate repair condition, rather than immediate conditions arising spontaneously. PHMSA understands that most defects that become immediate repair conditions are observable by ILI equipment well in advance of progression to an immediate repair condition. The repair criteria in this final rule are intended to assure that anomalies are repaired before they become an immediate condition and are at or near failure. In this final rule, PHMSA has included reference to ASME/ANSI B31.8S within each of §§ 192.714 and 192.933 to take into consideration other factors that operators currently consider when establishing remediation plans.

In this final rule, PHMSA has removed the proposed repair criteria under §§ 192.714 (non-HCAs) and 192.933 (HCAs) for SCC and selective seam weld corrosion, which were new repair criteria that contained the phrase ''any indication of.'' PHMSA combined SCC and selective seam weld corrosion repair criteria into a more general cracking repair criteria because each of these phenomena is, or results in, cracking. PHMSA included remediation measures for SCC under the requirements at § 192.929, which are the requirements for using direct assessment for SCC but did not require the remediation of ''any indication of'' SCC. PHMSA was not proposing to change any of the existing repair criteria that referenced ''any indication of,'' such as that for dents with any indication of metal loss, cracking, or a stress riser. Those repair criteria remain unchanged in this final rule.

F. Repair Criteria—§§ 192.714, 192.933

ii. Repair Criteria in Non-HCAs—§ 192.714

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed at § 192.713 repair criteria for non-HCA areas to assure that operators promptly repair injurious defects that are discovered outside of HCAs. These proposed repair criteria for non-HCAs were based on, and were similar, to, the repair criteria (regarding structure, anomaly types, and the repair timeframes) for HCA pipeline segments proposed at § 192.933.

For those anomalies for which a 1-year response is required on HCA pipeline segments, PHMSA proposed that a 2-year response would be required in non-HCA pipeline segments. This proposal would require operators to remediate anomalous conditions on gas transmission pipeline segments promptly and commensurate with the risk they present, while allowing operators to allocate their resources to those anomalies in HCAs that present a higher risk.

The specific anomalies and repair schedules for cracks, dents, and corrosion metal loss are discussed in their respective sections below.

2. Summary of Public Comment

Citizen groups, including Pipeline Safety Coalition, the PST, and Clean Water for North Carolina, supported the proposed provisions that would strengthen the repair criteria for HCAs and non-HCAs. Additionally, NAPSR and the NTSB supported PHMSA's revisions to the repair criteria.

Generally, the industry trade associations and pipeline operators supported PHMSA's intention of establishing repair criteria outside of HCAs but disagreed with some of the specific provisions. There was common agreement, however, that the processes for HCA repairs and non-HCA repairs should be standardized.

The trade associations and pipeline operators generally believed that the proposed provisions were too prescriptive and would impede operators from performing repairs based on risks. They further stated that the proposed provisions do not take into consideration other factors that operators currently consider when optimizing plans to remediate anomalies, such as historical data, geography, and congestion of the right-of-way.

AGA recommended that PHMSA create a new subpart to address assessment requirements outside of

[30] The GPAC voted on each section of the repair criteria separately, and each section is discussed in more detail below.

HCAs and add a section within that subpart to cover repair criteria. Several other trade associations and pipeline operators echoed AGA's recommendations.

Several industry commenters also stated that the rulemaking did not demonstrate that the safety benefit of strengthened repair criteria outweighs the costs. Multiple operators stated that the proposed repair provisions in § 192.713 would increase the number of digs operators would need to perform and asserted that the increased number of digs may not improve pipeline safety.

Certain commenters suggested that it would not be appropriate for PHMSA to require operators to repair immediate conditions in non-HCAs before repairing immediate conditions in HCAs, and that PHMSA should require operators to prioritize those conditions discovered within HCAs if operators discover multiple immediate conditions in HCAs and non-HCAs simultaneously. More specifically, AGA requested that the rule explicitly prioritize immediate conditions within HCAs over immediate conditions in other locations when conditions are discovered simultaneously and recommended that PHMSA adopt different terminology for ''immediate repair conditions'' inside and outside HCAs. Similarly, other industry trade organizations expressed concern that the proposed provisions for non-HCAs would complicate the allocation of resources to HCAs on a higher-priority basis when confronted with the large number of new, non-HCA pipelines needing assessments.

Commenters also requested PHMSA make the sections pertaining to non-HCA repairs and HCA repairs consistent regarding pressure reductions. Commenters representing the industry noted that, as proposed, certain notification requirements for long-term pressure reductions or for those operators unable to respond within the given timeframe were different depending on whether the pipeline was in an HCA or a non-HCA. These commenters suggested that those notification procedures be made consistent, wherever possible, between the HCA and non-HCA repair criteria. Multiple trade associations and pipeline industry entities also expressed concerns that the proposed provisions requiring ''an operator to reduce the operating pressure of its affected pipeline until it can remediate the immediate repair conditions'' are unnecessarily conservative. INGAA asserted that the proposed pressure reduction requirements for non-HCAs are more stringent than the pressure reductions requirements for HCAs, and several commenters offered alternative methods for determining appropriate operating pressure reductions. Specifically, these commenters requested PHMSA allow operators to take a pressure reduction other than 80 percent if they documented the analysis performed and assumptions used. These commenters claimed that, as proposed in the NPRM, operators were allowed to use a different pressure reduction in HCAs if an analysis supported it but were not allowed to do so in non-HCAs.

During its meeting in late March 2018, the GPAC recommended PHMSA clarify that pressure reductions would be required for immediate conditions in non-HCAs and in cases where repair schedules could not be met. As a part of this recommendation, the GPAC also recommended that operators notify PHMSA when they could not meet the schedule for anomaly evaluation and remediation or when a temporary pressure reduction exceeds 365 days. The GPAC also recommended that PHMSA should allow operators to calculate pressure reductions (following the discovery of repairable conditions) by using either class location factors, or 80 percent of the operating pressure, or 1.1 times the predicted failure pressure. The GPAC also recommended PHMSA require that operators document and keep records, for 5 years, of the calculations and decisions used to determine such pressure reductions and the implementation of the actual reduced operating pressure. Further, the GPAC recommended PHMSA avoid duplicating language regarding the need for repairs and pressure reductions found in other sections of the regulations.

3. PHMSA Response

In the 2019 Gas Transmission Rule, PHMSA promulgated new requirements for operators to conduct integrity assessments in areas outside of HCAs, including all Class 3 and Class 4 locations and the newly defined ''moderate consequence areas'' (MCA) that are piggable. This new requirement was in response to the congressional mandate in the 2011 Pipeline Safety Act (Pub. L. 112–90) to expand IM or elements of IM beyond HCAs. The non-HCA repair criteria PHMSA is issuing in this final rule are the companion requirements to those assessments and are necessary to extend the assessment and repair program elements of IM effectively to areas beyond HCAs. Although PHMSA agrees that this requirement will likely result in additional repairs, PHMSA believes it is necessary and important to assure that injurious defects are remediated before they lead to loss of pipeline integrity.

Commenters requested that the non-HCA repair criteria be split out from the general non-IM repair provisions that previously existed in the regulations. PHMSA determined that the non-HCA repair criteria would be clearer and easier to comply with if they were in a distinct section, and PHMSA has created a new § 192.714 with all of the non-HCA repair criteria.

To the comments that suggested that a different schedule be created for immediate conditions within HCAs and non-HCAs, PHMSA believes that the existing approach used in subpart O for HCAs is better because the identification of anomalies based on ILI results is an actionable indication that there might be an injurious defect in the pipeline. Establishing repair criteria based on operators discovering these actionable anomalies assures that the anomaly is investigated promptly and repaired, if necessary. PHMSA believes it is prudent for an operator to perform any necessary repairs once the operator has excavated the pipe and exposed the anomaly for field investigation, instead of deferring the repairs. Although PHMSA agrees that defects in HCAs, if they were to fail, could result in higher consequences, PHMSA reminds readers that ASME/ANSI B31.8S, section 7.2, defines an immediate condition as an ''indication show[ing] that [a] defect is at failure point.'' PHMSA believes that any indication of a pipe that is at the point of failure needs to be addressed immediately, and as such, for both HCAs and non-HCAs, operators must reduce pressure and immediately remediate the anomaly.

PHMSA agrees with several commenters and the GPAC recommendations for consistently addressing pressure reductions for repairs for both HCA and non-HCA pipeline segments. PHMSA believes that pressure reductions are needed for immediate conditions and when repair schedules cannot be met and has incorporated pressure reductions for non-HCA pipelines that are like the existing requirements for HCAs in subpart O, which include the operator notifying PHMSA. PHMSA also agrees that the amount of the pressure reduction should be established to be 80 percent of the operating pressure at the time of discovery of the defect, or the predicted failure pressure divided by 1.1, or the predicted failure pressure times the design factor for the class location in which the affected pipeline is located, and that records for such pressure reductions must be kept for a minimum of 5 years. PHMSA

incorporated these provisions, as recommended by the GPAC, in § 192.714(e) for non-HCA pipelines. Further, PHMSA followed the GPAC recommendation for reducing duplicative language regarding repairs and pressure reductions and has streamlined this final rule accordingly.

PHMSA also notes that AGA suggested creating a new subpart for non-HCA assessments and repairs. Although PHMSA has not created a new subpart, PHMSA believes it has accomplished the same purpose by putting the new non-HCA assessment and repair requirements in separate, distinct sections.

F. Repair Criteria—§§ 192.714, 192.933

iii. Cracking Criteria—§§ 192.714(d)(1)(v) & 192.933(d)(1)(v)

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to add criteria to address cracking and crack-like defects, including SCC, because the existing regulations have no explicit repair criteria for those types of critical defects. The cracking criteria would apply to both HCAs and non-HCAs, but they would require repair at different size thresholds and at different timeframes depending on the anomaly location.

Following the Enbridge incident near Marshall, MI, the NTSB recommended that PHMSA revise the hazardous liquid regulations at § 195.452 to state clearly: (1) when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed; (2) the acceptable methods for performing these engineering assessments, including the assessment of cracks coinciding with corrosion with a safety factor that considers the uncertainties associated with sizing of crack defects; (3) criteria for determining when a probable crack defect in a pipeline segment must be excavated and time limits for completing those excavations; (4) pressure restriction limits for crack defects that are not excavated by the required date; and (5) acceptable methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or SCC as applicable.[31] Although the recommendation was limited to hazardous liquid pipelines, the issue applies equally to gas transmission pipelines, as SCC can occur on these pipelines as well.

Therefore, in the NPRM, PHMSA proposed to allow operators to use an engineering critical assessment (ECA) to evaluate indications of SCC. If the SCC was ''significant,'' it would be categorized as an ''immediate'' repair condition. If the SCC was not ''significant,'' it would be categorized as a ''1-year'' condition. Further, PHMSA proposed to adopt the definition of significant SCC from the consensus industry standard NACE SP0204–2008. PHMSA also proposed that an operator could not use an ECA to justify not remediating any known indications of SCC.

The current regulations also do not have repair criteria for seam cracks or crack-like flaws. Current regulations also fail to address corrosion affecting a longitudinal seam and selective seam weld corrosion, which are time-sensitive integrity threats that behave like cracks and are categorized as crack-like defects. In the NPRM, PHMSA proposed to address these gaps by including repair criteria for cracks and crack-like flaws in § 192.933 and proposed similar criteria in § 192.713.

2. Summary of Public Comment

INGAA, API, and Piedmont strongly opposed the proposed provisions in § 192.713(d)(1)(v), that stated ''any indication of significant SCC'' constitutes an immediate repair condition. Commenters requested that PHMSA determine the repair condition of cracks and crack-like defects according to factors that capture the severity of the defect, such as predicted failure pressures or maximum depth. Many commenters believed that PHMSA's proposed criteria were too conservative and suggested the repair criteria be for anomalies with a crack depth of greater than 70 percent of the pipe wall thickness or with a predicted failure pressure of less than 1.1 times MAOP. Other commenters suggested PHMSA delete the definitions of specific significant crack defects and use the alternative cracking criterion proposed by PHMSA at the GPAC meeting on March 2, 2018.

INGAA recommended making the repair criteria for cracking consistent with the repair criteria for metal loss and suggested that PHMSA consider anomalies with a crack depth of 80 percent wall thickness as immediate conditions for this reason. INGAA also recommended that PHMSA adopt a failure pressure ratio approach for cracking.

Certain commenters noted that the classification of all cracks or crack-like defects as 2-year repair conditions was overly conservative and suggested PHMSA relax that requirement. For example, some commenters suggested requiring repairs at 50 percent crack depth or a predicted failure pressure of less than 1.25 times MAOP.

At the GPAC meeting, for the proposed repair criteria for cracks, members representing the industry stated PHMSA's criteria for the immediate repair of certain crack defects were too conservative and suggested establishing an immediate repair threshold for cracks up to 70 percent of wall thickness or those with a predicted failure pressure of less than 1.1 times MAOP rather than those cracks with a predicted failure pressure of less than 1.25 times MAOP. Members representing the public noted that public safety would be better served by the threshold for immediate crack repairs being more conservative but questioned whether the more stringent threshold would be practical.

Similarly, members representing the industry suggested that PHMSA's proposed criteria for 1-year and 2-year scheduled conditions were too conservative as well and suggested setting the relevant criteria as those cracks with a depth of 50 percent wall thickness or those cracks with a predicted failure pressure of less than 1.25 times MAOP. Members representing the industry also suggested that, in addition to relaxing the criteria for immediate cracks, PHMSA should also add language requiring operators to consider tool tolerance and other factors when examining crack growth rates. Further, members representing the industry suggested that PHMSA base the repair criteria on design conditions or design factors rather than class location factors. Committee members also suggested that PHMSA cross-reference specific regulatory language rather than repeat the text in full in other sections of the code.

Following the discussion, the committee voted 12–0 that, as published in the **Federal Register**, the provisions in the proposed rule and draft regulatory evaluation for cracking repair criteria were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) struck the proposed definitions of ''significant seam cracking'' and ''significant stress corrosion cracking,'' (2) deleted the phrase ''any indication of'' from the repair criteria related to cracking, (3) combined the criteria for SCC and seam cracking, (4) required that operators calculate predicted failure pressures for all time-dependent cracking anomalies by using the fracture mechanics

[31] NTSB Recommendation P–12–3, available at *https://www.ntsb.gov/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-12-003.*

procedure PHMSA developed, (5) revised the definition of ''hard spot'' as discussed,[32] and (6) considered specific crack repair criteria as immediate conditions. Those specific crack repair criteria for immediate conditions would include (1) crack depth plus corrosion greater than 50 percent of pipe wall thickness; (2) crack depth plus any corrosion is greater than the inspection tool's maximum measurable depth; or (3) the crack anomaly is determined to have a predicted failure pressure that is less than 1.25 times MAOP.

3. PHMSA Response

In this final rule, PHMSA did not adopt the proposed definitions of ''significant seam cracking'' and ''significant stress corrosion cracking.'' With the revisions to the cracking repair criteria, these definitions weren't necessary. Similarly, with the deletion of the proposed repair criteria using those specific definitions, the recommendation for deleting the phrase ''any indication of'' from those criteria, became moot. Further, PHMSA's revisions to the cracking repair criteria also made the recommendation for PHMSA to combine the proposed SCC criteria and the seam cracking criteria moot.

PHMSA believes that the repair criteria it proposed in the NPRM for cracks are consistent with research findings and provides an adequate safety margin while accounting for the severity of the defects through the analysis of the predicted failure pressure.[33] PHMSA believes the repair criteria for cracks that were suggested by some of the commenters would not provide an adequate safety margin due to factors including the accuracy of tool results, varying pipe toughness, and pressure cycling. This was discussed at length by the GPAC, who ultimately recommended that anomalies be classified as immediate conditions where the crack depth plus corrosion is greater than 50 percent of pipe wall thickness, compared to certain commenters who suggested that cracks with a depth of up to 70 percent pipe wall thickness be classified as immediate conditions.

While the GPAC did not have an explicit recommendation for scheduled (*i.e.,* non-immediate) crack repair criteria, they recommended that PHMSA consider a repair schedule for cracks that is less conservative than what was proposed in the NPRM. Their recommended schedule is: 1.39 times MAOP for Class 1 and 2 locations and 1.5 times MAOP for Class 3 and 4 locations. PHMSA considered this recommendation and determined that the condition should cover Class 1 locations and Class 2 locations containing Class 1 pipe that has been uprated in accordance with § 192.611, where the predicted failure pressure is 1.39 times MAOP. For all other Class 2 locations and higher class locations, the predicted failure pressure would be 1.5 times MAOP. Section 192.611 allows Class 1 pipe to remain in a Class 2 location if it has had a subpart J pressure test, for 8 hours, at 1.25 times MAOP. Also, it allows pipe with a design factor of 0.72, with the reciprocal of 1 divided by 0.72 being equal to 1.39, which is the predicted failure pressure. Therefore, PHMSA elected to apply a predicted failure pressure ratio of 1.39 times MAOP to both Class 1 pipe and uprated Class 2 pipe.

For immediate conditions, the GPAC asked PHMSA to consider if a less conservative repair criterion of 1.1 times MAOP (after tool tolerance had been applied) would be appropriate. PHMSA considered this suggestion but notes that, after allowing for pressure excursions above MAOP due to over pressure protection device settings, the actual safety margin of such an approach would be between 0 and 6 percent. PHMSA has determined that this safety margin for immediate crack conditions is inadequate and, for this final rule, has retained the requirement that operators must immediately repair crack anomalies with a predicted failure pressure that is less than 1.25 times MAOP.

PHMSA took technical guidance information from several sources into account regarding significant SCC and significant seam weld corrosion when creating the repair criteria for these anomalies, including ASME ST–PT–011 (''Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'').[34]

ASME ST–PT–011 states that stress corrosion cracks are ''Noteworthy'' if the maximum crack depth is greater than 10 percent of the wall thickness and if the maximum interacting crack length is more than the critical length of a 50 percent through-wall crack at a stress level of 110 percent SMYS.[35] The report provides categories as follows:

Category 1: Predicted Failure Pressure (PFP) is above 110 percent SMYS (note that 110 percent SMYS is used to delineate Category 1 cracks because it corresponds to the pressure most commonly prescribed for hydrostatic testing).

Category 2: PFP is above 125 percent MAOP[36] and below 110 percent SMYS.

Category 3: PFP is above 110 percent MAOP and below 125 percent MAOP.

Category 4: PFP is below 110 percent MAOP.

Category Zero: A crack below the threshold for Noteworthy cracks. These typically fall into two groups: (1) Those that are shallow (*i.e.,* less than 10 percent through-wall depth), or (2) Those that are so short that, even if they were 50 percent through-wall depth, they would not result in a hydrostatic test failure.

In this final rule, operators can use an engineering analysis on cracks in Categories 1 through 2 as described above. However, any Category 3 or 4 cracking defect below 125 percent MAOP would require immediate remediation. Category 3 cracks would have a 10 percent or greater safety factor, which is similar to how PHMSA currently treats corrosion anomalies at § 192.933. PHMSA provides more conservatism in the cracking criteria because there is more uncertainty with the accuracy of current ILI technology in its ability to measure crack length and depth, as well operational factors.

These severity categories allow operators to estimate the minimum remaining life at operating pressure for each category. The following estimates from ASME ST–PT–011 are based on the time it would take for the crack depth to increase to a failure-causing depth at the operating pressure. For pipelines operating at 72 percent SMYS, the following minimum operational lives for each category of cracks are as follows:

[32] This is discussed more under the ''Definitions'' subsection of this section.

[33] See ASME, ''STP–PT–0011:Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'' (2008). See also Young, B.A., et al., ''Comprehensive Study to Understand Longitudinal ERW Seam Failures'' (2017), available at *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.* Both papers call for anomaly evaluation; the knowledge of certain properties, including the length and depth of the crack, and pipe properties like wall thickness, grade, and toughness; and a proposed safety factor based on the time until the next assessment period. The papers also require that the depth of a crack not be greater than the depth of the assessment tool's tolerance. See § 192.712(e).

[34] ASME, ''STP–PT–011: Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'' (2008).

[35] PHMSA notes that 110 percent SMYS for a Class 1 pipeline is roughly equivalent to 1.49 times MAOP.

[36] PHMSA notes that 125% times MAOP for a pipeline that operates at 72% SMYS in a Class 1 location would correspond to roughly 90% SMYS for a Category 2 crack. PHMSA has defined in § 192.506 that a spike test for cracking should be conducted at a pressure of 100 percent of SMYS (roughly equivalent to 1.39 times MAOP for a Class 1 location) or 1.5 times MAOP.

Category Zero: Failure life exceeds 15 years (for short cracks) to 25 years (for shallow cracks).

Category 1: Failure life exceeds 10 years.

Category 2: Failure life exceeds 5 years.

Category 3: Failure life exceeds 2 years.

Category 4: Failure may be imminent.

ASME ST–PT–011 further states that mitigating a pipeline segment with SCC should be commensurate with the severity of the discovered crack, which would reflect the PFP and the estimated life at the operating pressure. For example, Category Zero cracks may warrant no more than ongoing SCC condition monitoring and reassessment after a period of 7 years. Cracks may be best assessed by direct assessment, hydrostatic testing, or ILI. The most severe cases would require an immediate pressure reduction, repair (if the location is known), and hydrostatic testing or ILI, followed by replacing the pipe or installing an appropriate sleeve over the crack or known cracking areas.

F. Repair Criteria—§§ 192.714, 192.933

iv. Dent Criteria—§§ 192.714 & 192.933

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed that dents in non-HCA segments with any indication of metal loss, cracking, or a stress riser would be considered ''immediate'' repair conditions. Additionally, PHMSA proposed that dents meeting the ''1-year'' repair conditions under § 192.933 would be required to be repaired in non-HCAs within 2 years.

2. Summary of Public Comment

Multiple commenters, including the industry trade associations and operators, disagreed that all dents with metal loss should be considered immediate repair conditions. These commenters requested that PHMSA's final rule address different kinds of dents separately. Many pipeline operators stated that dents with metal loss from ''scratches, gouges, and grooves'' are appropriate as immediate repair conditions, while dents caused by corrosion are lower risk and should be conditions scheduled for later repair. Several organizations cited API Publication 1156 [37] and ASME/ANSI B31.8, ''Gas Transmission and Distribution Piping Systems,'' to support these claims. Several commenters also recommended that PHMSA impose different response timelines for dents depending on the location and the manner of the dents, because dents with bottom-side metal loss are usually corrosion-related and low-risk, while dents on the top of the pipeline with metal loss are likely to be from mechanical damage and are at a higher risk to fail. This distinction would be consistent with the criteria for smooth dents (dents with no peaks, buckling, gouging, cracking, or metal loss that can reduce the operational life of the pipe).

With further regard to the repair criteria for dents, commenters representing the industry believed PHMSA should allow operators to use an ECA to evaluate dents as an alternative to following the prescribed repair criteria. Some of this discussion focused on whether PHMSA should include a finite element analysis (FEA) [38] as part of the ECA and whether PHMSA should define critical strain levels as a criterion in the ECA. Comments from industry additionally suggested that the criterion related to gouges or grooves greater than 12.5 percent of wall thickness was duplicative with other criteria. Industry trade associations noted that gouges and grooves would be evaluated in accordance with the dent, metal loss, or cracking criteria, and therefore, a separate anomaly category for gouges and grooves should be removed. Further, they asserted that current ILI technology can't determine the specific cause of metal loss, which would make this criterion unfeasible.

At the GPAC meeting on March 26, 2018, the committee recommended changes to several of the specific repair criteria for cracks, corrosion metal loss, and dents. Specific to dents, the committee recommended that PHMSA allow use of an ECA to evaluate certain dent-related anomalies and incorporate the ECA into the repair criteria.[39]

Following the discussion, the committee voted 12–0 that, as published in the **Federal Register**, the provisions in the proposed rule and draft regulatory evaluation for dent repair criteria were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) allowed operators to use an ECA for specific dent-related repair criteria and considered language to accommodate alternative ECA methods (including an FEA), and (2) distinguished between top-side dents that exceeded critical strain levels and bottom-side dents that exceeded critical strain levels by making distinct criteria for those anomalies.

3. PHMSA Response

PHMSA believes that the repair criteria it proposed in the NPRM for dents provide an adequate safety margin and believes the criteria for dents that were suggested by some of the commenters would not provide adequate safety margin. PHMSA based this judgment on R&D programs that have been sponsored by PHMSA and the Pipeline Research Council International, and on elements of dent repair criteria that are contained within API RP 1183.[40]

PHMSA agrees with the GPAC recommendation for allowing an ECA method to evaluate dent anomalies and has revised the dent repair criteria for immediate, scheduled, and monitored conditions, as recommended by GPAC, to do so. PHMSA believes that the development of high-resolution deformation ILI tools has advanced enough to justify allowing operators to use an ECA method to evaluate dent anomalies and believes that it would be consistent with public safety while providing operators additional flexibility. While this rulemaking was under development, API published API RP 1183, which provides guidance for assessing and managing dents that are present in pipeline systems as a result of contact by rocks, machinery, or other forces. The RP presents guidance for developing a dent assessment and management program by (1) providing suitable methods for inspecting and characterizing the condition of the pipeline with respect to dents; (2) establishing data screening processes to evaluate dents relative to the extent and degree of deformation and operational severity; (3) providing response criteria for dents based on the dent shape and profile as determined by ILI; (4) applying engineering assessment methods to evaluate the fitness-for-service of dents, including the reassessment interval; (5) presenting remediation and repair options to address dents; and (6) developing preventive and mitigative measures for dents in lieu of, or in addition to,

[37] API, ''Pub. 1156: Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines'' (1997).

[38] FEA is a modeling technique used to find and solve structural or integrity issues for phenomena such as cracking or denting. Pipe properties, including the parameters of the damage to the pipe, planned operating pressure, lifespan until the next evaluation, and any future operational conditions (max pressure, pressure cycle, higher temperatures), are needed to perform an FEA.

[39] Many of the recommended changes to the proposed repair criteria were highly technical in nature. For more information, including transcripts of the discussion and the voting slides, please visit: *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=132.*

[40] API, Recommended Practice 1183, ''Assessment and Management of Dents in Pipelines'' (Nov. 2020).

periodic dent integrity assessment, including pressure reductions and pressure cycle management.

PHMSA agrees with commenters that the criteria based on gouges and grooves would be duplicative with other criteria being proposed in the NPRM, namely the criteria related to metal loss anomalies. Accordingly, PHMSA has removed the criteria related to gouges and grooves from this final rule.

In the 2019 Gas Transmission Rule, PHMSA finalized an ECA method for operators to use as a part of the pipeline material property and attribute verification under § 192.607 and the MAOP reconfirmation requirements of § 192.624. A key aspect of that ECA method is the detailed analysis of the remaining strength of pipe with known or assumed defects. The 2019 Gas Transmission Rule created a new section, § 192.712, to address the techniques and procedures an operator could use to analyze the predicted failure pressures for pipe with corrosion metal loss and cracks or crack-like defects.[41] That analysis requires the conservative analysis of the defect to determine the remaining life of the pipeline. In this final rule, PHMSA is building on the provisions it promulgated in the 2019 Gas Transmission Rule by allowing operators to use such an analysis for determining the timing of certain anomaly repairs, including dents. Unlike the previously existing repair criteria, which required the repair of listed anomalies within a specific timeframe, operators, per this final rule, can perform this analysis to determine whether the predicted failure pressure of the anomaly would warrant additional monitoring and a later repair. PHMSA understands that operators may propose, for PHMSA review in accordance with § 192.18, procedures for the assessment and remediation of dent anomalies (such as an ECA for dent anomalies); operators may develop those procedures using consensus industry standards (*e.g.,* API RP 1183, ASME B31.8, ASME B31.8S) or current research findings.

F. Repair Criteria—§§ 192.714, 192.933

v. Corrosion Metal Loss Criteria—§§ 192.714 & 192.933

1. Summary of PHMSA's Proposal

The required remediation of several types of corrosion defects that are incorporated in the hazardous liquid regulations in part 195 are currently omitted from part 192. The current gas transmission IM regulations allow operators to use ASME/ANSI B31.8S, Figure 4, for guiding repair decisions not specified in § 192.933(d), which can allow operators significant discretion in assessing and remediating pipe with corrosion or metal loss defects. PHMSA has found a wide variation in operators' interpretation of how to meet the requirements of the regulations in assessing, evaluating, and remediating corrosion and metal loss defects.

To address these gaps, and to harmonize part 192 with part 195, PHMSA proposed to amend § 192.933 to designate as immediate repair conditions those anomalies where metal loss is greater than 80 percent of nominal wall thickness and for indications of metal loss affecting certain legacy pipe with longitudinal seams.

To address gaps related to non-immediate conditions, the NPRM proposed that operators must repair the following within 1 year: (1) anomalies where a calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the anomaly less than or equal to 1.25 times the MAOP for Class 1 locations, 1.39 times the MAOP for Class 2 locations, 1.67 times the MAOP for Class 3 locations, and 2.00 times the MAOP for Class 4 locations (comparable to the alternative design factor specified in § 192.620(a)); (2) areas of general corrosion with a predicted metal loss greater than 50 percent of nominal wall thickness; (3) anomalies with predicted metal loss greater than 50 percent of nominal wall thickness that are located at crossings of another pipeline, are in areas with widespread circumferential corrosion, or are in areas that could affect a girth weld; and (4) anomalies with metal loss due to gouges or grooves[42] that are greater than 12.5 percent of nominal wall thickness.

2. Summary of Public Comment

A commenter noted that PHMSA should recognize that gouges and scrapes are metal loss defects that can be smoothed by grinding to eliminate stress concentrations.

Multiple commenters also provided input on the proposed provisions that determine repair criteria for metal loss affecting certain pipe with longitudinal seams. INGAA, AGA, and a pipeline industry entity generally supported a classification of ''immediate'' for anomalies with ''an indication of metal loss affecting a detected longitudinal seam, if that seam was formed by direct current or low frequency or high frequency electric resistance welding or by electric flash welding.'' However, PG&E requested that PHMSA not classify metal loss affecting a detected longitudinal seam as an immediate repair condition if that seam was formed by high-frequency electric resistance welding, as that pipe is considered ductile. National Fuel requested that PHMSA categorize longitudinal seam metal loss based on a minimum metal-loss threshold rather than ''an indication.'' Certain commenters requested PHMSA allow operators to perform a fitness-for-service evaluation or ECA on selective seam weld corrosion.

Kern River suggested PHMSA should consider applicable manufacturing and tool detection tolerances in the establishment of repair criteria that require response to ''any indication of metal loss.''

Several commenters, including AGA, Pauite, and DTE, did not support the proposed inclusion of ''any indication of significant seam weld corrosion'' in § 192.713(d)(1)(vi). INGAA and AGA asserted that seam weld corrosion can only be conclusively determined by an in-field examination even though ILI tools are often employed to identify possible seam weld corrosion areas.

INGAA requested that gouge and groove metal loss anomalies be deleted from the 1-year and 2-year response conditions. Other commenters noted that current ILI tools do not have the capability of differentiating 12.5 percent gouge or groove metal loss anomalies from 12.5 percent external corrosion metal loss anomalies and suggested PHMSA delete this proposed requirement. These commenters argued that, given current ILI technology and per this proposal, operators would be required to investigate all metal loss indications greater than 12.5 percent to determine if the metal loss was a gouge or groove. Several trade associations and pipeline industry entities requested that operators be allowed to perform excavations to validate ILI results before classifying a segment as a high-priority repair.

Several pipeline industry commenters disagreed with the proposed repair criteria and repair methods that differed from industry standard ASME/ANSI B31.8S. For example, AGA stated that they opposed the inclusion of different repair criteria for different class locations because this contradicts ASME/ANSI B31.8S. API noted that PHMSA's proposal contradicted the ASME/ANSI standard by including depth-based criteria and also stated that PHMSA should not include the depth-

[41] See 84 FR 52236, 52237.

[42] Gouges or grooves are stress concentrators that lead to cracking and fatigue, which in turn may lead to accelerated failure.

based criteria but only reference ASME/ANSI B31.8S, which is considered the best accepted practice. Similarly, INGAA recommended that PHMSA allow operators to use the repair methods in ASME/ANSI B31.8S rather than the proposed criteria.

Some commenters thought that the new proposed criteria for corrosion anomalies made the existing corrosion repair requirements at § 192.485(c) duplicative and requested PHMSA delete the existing corrosion repair requirements for clarity. Other commenters noted that PHMSA's proposed requirement for corrosion greater than 50 percent of wall thickness was redundant to other proposed corrosion metal loss defects and suggested this specific item should be deleted. Similarly, commenters suggested that the criteria for predicted metal loss greater than 50 percent of nominal wall located at the crossing of another pipeline, areas with widespread circumferential corrosion, or areas that could affect a girth weld were both too conservative and duplicative of other corrosion repair criteria.

At the GPAC meeting on March 26, 2018, regarding the general provisions and applicability of the corrosion metal loss repair criteria, commenters representing the industry noted that for 1-year and 2-year scheduled conditions, the use of class location safety factors would be burdensome, as it would require more frequent repairs for pipelines in Class 2, Class 3, or Class 4 locations than contemplated by consensus industry standard ASME/ANSI B31.8S section 7, figure 4.

The committee also discussed specific requirements related to the repair of corrosion anomalies. Echoing many of the public comments on the topic, members representing the industry believed that the newly proposed corrosion repair requirements were either overly conservative or duplicative compared to existing repair requirements in the corrosion control subpart. These committee members suggested the new requirements should be deleted or otherwise changed to be less conservative. Additionally, these members noted that the proposed criteria for anomalies where corrosion is greater than 50 percent of wall thickness would be redundant with other repair criteria for evaluating corrosion metal loss defects using accepted analysis techniques, such as ASME B31G and remaining strength of corroded pipe (RSTRENG).[43] Further, for corrosion metal loss affecting pipe seams, members representing the industry suggested the criteria should apply to corrosion that ''preferentially'' affects the long seam,[44] and that PHMSA should allow an ECA to analyze such defects to prevent unnecessary excavations.

The committee also suggested that PHMSA evaluate predicted failure pressure ratings and thresholds for remediation schedules of anomalies at pipeline crossings with widespread circumferential corrosion or with corrosion that can affect a girth weld.

Following the discussion, the committee voted 11–0 that, as published in the **Federal Register**, the provisions in the proposed rule and draft regulatory evaluation for corrosion metal loss repair criteria (excluding the repair timing) were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) clarified that the criteria do not apply to corrosion pits near a long seam but does apply to corrosion along seams that could lead to slotting-type crack-like defects, (2) deleted duplicative criteria, (3) cross-referenced the proposed new fracture mechanics section with the general corrosion remediation requirements, and (4) revised the repair criteria for scheduled conditions regarding the predicted failure pressure as discussed by the committee.

The committee then voted 8–3 (with each of two members representing State regulators and one member representing the public dissenting) that, as published in the **Federal Register**, the provisions in the proposed rule and draft regulatory evaluation for scheduled conditions regarding the predicted failure pressure repair criteria for corrosion metal loss anomalies were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) incorporated ASME/ANSI B31.8S, section 7, figure 4, into the repair criteria; (2) required operators to consider ILI tool tolerance on all runs; (3) removed and revised the predicted failure pressure standards for metal loss anomalies per the discussion of the committee; and (4) provided guidance to improve the understanding and use of ASME/ANSI B31.8S, section 7, figure 4.

For corrosion metal loss anomalies that meet the ''scheduled'' criteria (*i.e.,* 1-year conditions for HCAs and 2-year conditions for non-HCAs), the GPAC voted 8–3 that PHMSA should remove the predicted failure pressure standards for Class 1 and Class 2 segments from the NPRM and require operators to use section 7, figure 4 from ASME/ANSI B31.8S instead (*i.e.,* retain the current requirement in place for HCAs under subpart O).

3. PHMSA Response

When developing the repair criteria in the NPRM, PHMSA evaluated grounding the predicted failure pressure for those criteria in one or more of the following three factors: (1) the test pressure of a pipeline, (2) the design factor of a pipeline, and (3) the HCA repair criteria. Because PHMSA sought to improve upon existing HCA repair criteria, PHMSA decided against using that factor as the basis for calculating predicted failure pressures and proposed using test pressure or design factor of a pipeline instead. PHMSA based its proposed threshold for Class 1 pipelines (less than or equal to 1.25 times MAOP predicted failure pressure) on the maximum test pressure in § 192.619 for Class 1 pipelines (1.25 times MAOP). For the repair thresholds for Class 2, Class 3, and Class 4 pipelines, PHMSA calculated predicted failure pressures using the reciprocals of the design factors listed at § 192.111 for the immediately preceding class location rating. This approach ensured an adequate margin to failure even if the pipeline were to experience a one-class bump (pursuant to § 192.611) from changes in population density of the surrounding area. The resulting predicted failure pressure thresholds were less than or equal to 1.39 times MAOP (reciprocal of the 0.72 Class 1 design factor) for pipelines in a Class 2 location, less than or equal to 1.67 times MAOP for pipelines in Class 3 locations, and less than or equal to 2.00 times MAOP for pipelines in Class 4 locations.

PHMSA believes the repair criteria for corrosion metal loss that were suggested by some of the commenters would not provide adequate safety margin compared to what PHMSA proposed in the NPRM. This was discussed at length by the GPAC, who recommended repair criteria that, in some cases, were less conservative than what PHMSA proposed in the NPRM.

In this final rule, PHMSA adopted the GPAC's recommendation to incorporate ASME/ANSI B31.8S section 7, figure 4, into the repair criteria by requiring operators to use it in Class 1 locations for metal loss anomalies with a

[43] Both are incorporated by reference at § 192.7; see (c)(4): ASME/ANSI B31G–1991 (Reaffirmed 2004), ''Manual for Determining the Remaining Strength of Corroded Pipelines,'' 2004, and (j)(1): AGA, Pipeline Research Committee Project, PR–3–805, ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,'' (December 22, 1989).

[44] Corrosion that ''preferentially'' affects the long seam is corrosion that is of and along the weld seam that is classified as selective seam weld corrosion. It normally effects low frequency electric resistance weld seams (LF–ERW) and electric flash welded seams (EFW).

predicted failure pressure greater than 1.1 times MAOP, which is consistent with the previous IM repair regulations. The committee also recommended PHMSA provide additional guidance on the use of ASME/ANSI B31.8S section 7, figure 4. ASME/ANSI B31.8S, section 7, figure 4 has three scales for repair that are based on the MAOP of the pipeline and the MAOP's percentage of the pipeline's SMYS.[45] Operators can use one of the 3 sliding scales of figure 4, as appropriate, to address anomalies when the anomaly has a failure pressure ratio above 1.1. As discussed previously, operators are currently required to follow ASME/ANSI B31.8S section 7, figure 4 under elements of the previous IM repair regulations. PHMSA understands that the 10 percent nominal safety margin provided by compliance with ASME/ANSI B31.8S section 7, figure 4 is appropriate for the relatively low risk to public safety posed to pipelines in low-population-density, Class 1 locations.

However, PHMSA did not accept the GPAC's recommendation for Class 2 locations. The number of immediate repair conditions being discovered during reassessments in Class 2 locations continues at approximately the same rate as they were discovered during the baseline assessment phase of the IM rule promulgated in 2004, according to PHMSA annual report data. PHMSA attributes this to defects that are not repaired and allowed to grow to a size that are at or near failure (*i.e.,* an immediate condition). Existing immediate repair criteria for pipelines in Class 2 locations (predicated on ASME/ANSI B31.8S section 7, figure 4) allow up to a maximum 10 percent safety margin over the MAOP. However, after allowing for pressure excursions above MAOP due to overpressure protection device settings, the actual safety margin is between 0 and 6 percent. PHMSA has determined that the continued reliance on those ASME/ANSI B31.8S section 7, figure 4-derived safety margins in more densely populated Class 2 locations does not ensure adequate identification and elimination of sub-critical defects before they grow to a size that would raise immediate safety concerns. Therefore, in this final rule, PHMSA chooses to retain the NPRM's predicted failure pressure threshold for metal loss anomalies in Class 2 locations of less than 1.39 times MAOP.

For Class 3 and Class 4 locations, PHMSA considered predicted failure pressure thresholds between 1.39 times and 1.50 times MAOP as requested by the committee. However, PHMSA has determined that, in order to provide adequate margin for public safety in higher- population-density Class 3 and 4 locations, PHMSA could not establish a predicted failure pressure threshold as low as 1.39 times MAOP. Therefore, in this final rule, PHMSA has provided a repair threshold for anomalies meeting a predicted failure pressure of less than 1.50 times MAOP for pipelines in Class 3 and Class 4 locations. PHMSA notes this approach would align repair criteria with the approach in § 192.619 for determining maximum allowable pressures for the same locations, and reflects that transmission pipelines in Class 3 and Class 4 locations are more robust (as a result of thicker walls and other design requirements) than those used in Class 1 and Class 2 locations.

PHMSA has provided similar repair criteria in this final rule for corrosion metal loss anomalies that are at a crossing of another pipeline; are in an area with widespread circumferential corrosion; could affect a girth weld; or that preferentially affects detected longitudinal seams that are formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0. Specifically, PHMSA is requiring the repair of conditions that reach less than 1.39 times the MAOP for anomalies in Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611. For those corrosion metal loss anomalies at all other Class 2 locations, as well as those anomalies in Class 3 and Class 4 locations, operators will have to repair them once they reach a predicted failure pressure of less than 1.50 times MAOP.

PHMSA is requiring the additional stringency in Class 1 locations and Class 2 locations compared to the general corrosion metal loss repair standard discussed above because, should corrosion at the crossing of other pipelines induce failure, multiple pipelines could be damaged or fail. Pipelines with anomalies located at areas of widespread circumferential corrosion could additionally lose pipe strength due to outside longitudinal (pulling force) loading on the pipeline. And, historically, longitudinal seams that are formed by direct-current welding, low-frequency or high-frequency electric resistance welding, electric flash welding, or that have a longitudinal joint factor of less than 1.0, are more likely to fail. Therefore, PHMSA has determined that more stringent repair criteria are necessary for corrosion metal loss anomalies that preferentially affect these longitudinal seams. In contrast, because pipelines in Class 3 and Class 4 locations are (as noted above) more robust than those in Class 1 and Class 2 locations, PHMSA has determined that it is unnecessary to impose different thresholds for pipelines in Class 3 and Class 4 locations based on whether they are located at the crossing of another pipeline.

As explained in the discussion for dent anomalies above, PHMSA agreed with commenters that the specific criteria for gouges and grooves was duplicative with other metal loss conditions and has chosen not to finalize gouge and groove criteria in this final rule. Therefore, the comments related to whether ILI tools can properly or reliably identify gouges and grooves specifically are moot.

F. Repair Criteria—§§ 192.714, 192.933

vi. General Discussion

Process for Analyzing Defects Discovered—§ 192.933

1. Summary of PHMSA's Proposal

Following the Enbridge hazardous liquid incident in 2010 that spilled nearly 1 million barrels of oil near Marshall, MI, in 2010, the NTSB recommended that PHMSA revise requirements in the hazardous liquid pipeline safety regulations at § 195.452(h)(2) related to the ''discovery of condition'' to require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators notify PHMSA and provide an expected date when adequate information will become available.[46] The NTSB also recommended that PHMSA revise part 195 to state the acceptable methods for performing engineering assessments of ILI results, including the assessment of cracks coinciding with corrosion, with a safety factor that considers the uncertainties associated with sizing of crack defects (P–12–3). Although these recommendations were for the hazardous liquid pipeline safety regulations in part 195, the issues apply equally to gas pipelines regulated under part 192.

Accordingly, PHMSA proposed to amend paragraph (b) of § 192.933 to

[45] Those three scales pertain to (1) not exceeding 30 percent SMYS, (2) above 30 percent SMYS but not exceeding 50 percent SMYS, and (3) above 50 percent SMYS.

[46] NTSB Recommendation P–12–4, available at *https://www.ntsb.gov/safety/safety-recs/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-12-004.*

require that operators notify PHMSA within 180 days following an assessment where the operator cannot obtain sufficient information to determine if a condition presents a potential threat to the integrity of the pipeline; and expand the requirements in § 192.933 to clarify that operators must assure that persons qualified by knowledge, training, and experience must analyze the data obtained from an ILI to determine if a condition could adversely affect the safe operation of the pipeline. PHMSA also proposed to require that operators explicitly consider uncertainties in reported results in identifying and characterizing anomalies, which includes uncertainties in tool tolerance, detection threshold, the probability of detection, the probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots.

PHMSA also proposed to amend paragraphs (a) and (d) of § 192.933 to require that operators document a pipeline's physical material properties and attributes that are used in remaining strength calculations in reliable, traceable, verifiable, and complete records. If such records were not available, operators would be required to base the pipe and material properties used in the remaining strength calculations on properties determined and documented in accordance with § 192.607.

2. Summary of Public Comment

Commenters noted that there were potential issues with how the revised repair criteria and the proposed material verification requirements at § 192.607 would interact regarding remaining strength calculations. These commenters requested that, absent reliable data, PHMSA allow operators to use supportable, sound engineering judgments when calculating remaining strength. This would allow operators to establish the remaining strength of affected segments while material verification was completed. Similarly, commenters suggested if the value for specified minimum yield strength is unknown, operators should be able to use a conservative default value, such as 30,000 pounds per square inch (psi). For predicted failure pressure calculations, operators suggested they should be able to use the records they have on hand and operator knowledge for calculations until any necessary material properties are verified through § 192.607. Similarly, at the GPAC meeting on March 26, 2018, commenters representing the industry suggested PHMSA should allow, in the absence of traceable, verifiable, and complete material records,[47] for operators to use sound engineering judgment or otherwise conservative assumptions in repair-related decision making, and recommended PHMSA modify the regulations as such.

The EDF and PST supported PHMSA's proposals related to considering uncertainties in ILI results for identifying and characterizing anomalies. Several pipeline operators and industry trade associations on the other hand, including INGAA, expressed concern that the NPRM would require pipeline operators to repair anomalies that do not threaten pipeline integrity, stating that many anomalies that are identified by indirect measurements as requiring repair are later determined not to require repair upon examination in the field. These commenters requested that PHMSA change the proposed requirements to distinguish between ILI results and in-field examinations and start the repair timeline with the time an anomaly is examined in the field and not when it is identified by ILI.

INGAA suggested that PHMSA change the proposed requirements to differentiate between response, remediation, and repair, and that PHMSA replace ''repair'' with ''response'' in the terms ''2-year repair criteria'' and ''1-year repair criteria'' as those terms pertain to the non-HCA repair criteria. INGAA also requested that PHMSA further divide ''2-year response conditions'' into ''2-year response conditions and scheduled responses'' and similarly divide ''1-year response conditions'' into ''1-year response conditions and scheduled responses.'' INGAA suggested such a revision would be necessary because the proposed requirements for the response to, and repair of, potential pipeline anomalies do not recognize the differences between actions that operators take when evaluating the result of integrity assessments versus those actions operators take following in-field examinations of potential anomalies.

Several commenters requested that PHMSA change the proposed regulatory language to distinguish between ILI results and in-field examinations (response) and the actual remediation activity (repair) with a view to start the repair timeline after an anomaly is examined in the field and not when it is identified by ILI. Commenters suggested separate timelines to distinguish between the ''response'' and ''repair'' phases of pipeline remediation.

3. PHMSA Response

PHMSA addressed comments pertaining to the use of sound engineering judgment and assumed values to evaluate anomalies when data required for the evaluation is unknown or not available in traceable, verifiable, and complete records in the 2019 Gas Transmission Rule at § 192.712.[48] If an operator does not have one or more of the material properties necessary to perform an ECA analysis (diameter, wall thickness, seam type, grade, and Charpy v-notch toughness values, if applicable), the operator must use the conservative assumptions PHMSA provided and include the pipeline segment in its program to verify the undocumented information in accordance with the material properties verification requirements at § 192.607.

In the Response to Petitions for Reconsideration on the 2019 Gas Transmission Rule,[49] PHMSA stated that if operators are missing any material properties during anomaly evaluations and repairs, operators must confirm those material properties under §§ 192.607 and 192.712(e) through (g). For consistency in this final rule, and to make this requirement more explicit, PHMSA has linked those material property confirmation requirements to the anomaly repair requirements by cross-referencing § 192.607 at both §§ 192.714 and 192.933. PHMSA will also note that, in accordance with the section 23 mandate in the 2011 Pipeline Safety Act, operators reported that approximately 13 percent of pipeline segment mileage in HCAs and Class 3 and Class 4 locations lack adequate documentation of the physical and operational characteristics of the pipelines necessary to confirm the proper MAOP. Such documentation is

[47] In an advisory bulletin dated May 7, 2012 (77 FR 26822), PHMSA provided guidelines for what records would meet a traceable, verifiable, and complete standard. The phrase ''traceable, verifiable, and complete'' matched a phrase from NTSB recommendation P–10–5, which recommended to the California Public Utilities Commission to ensure that PG&E ''aggressively and diligently searched documents and records relating to [. . .] natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas [. . .]. These records should be traceable, verifiable, and complete [. . .].'' See NTSB Recommendation P–10–5, available at *https://www.ntsb.gov/safety/safety-recs/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-10-005.* While PHMSA proposed that records meet a reliable, traceable, verifiable, and complete standard, PHMSA believes that being consistent with the guidance it provided in the May 2012 advisory bulletin and the NTSB recommendation will provide further clarity.

[48] See 84 FR 52236, 52251.

[49] 85 FR 40132 (July 6, 2020).

also critical for performing predicted failure pressure calculations.

In an earlier section of the repair criteria discussion, PHMSA noted that the identification of anomalies based on ILI results is an actionable indication that there might be an injurious defect in the pipeline. Establishing repair criteria based on operators discovering these actionable anomalies assures that these anomalies are investigated promptly and repaired. Therefore, PHMSA disagrees with commenters who suggested that there should be separate timelines for anomaly responses and repairs, as it would be prudent for operators to perform any necessary repairs once the operator has excavated the pipe and exposed the anomaly for investigation rather than deferring such repairs.

F. Repair Criteria—§§ 192.714, 192.933

vii. Miscellaneous Comments

1. Summary of Public Comments

Commenters were concerned that the requirements in this rulemaking would apply to gas gathering pipelines and requested that PHMSA clarify this is not the case. Similarly, the GPAC, in its late March 2018 meeting, recommended PHMSA clarify that the non-HCA repair criteria applied to those pipeline segments not currently covered under the IM regulations at subpart O.

Additionally, pipeline operators and their trade associations requested that PHMSA clarify the effective date of the repair provisions, as the requirements were proposed in an allegedly retroactive section of the regulations. These commenters claimed, as written, the proposed provisions would force operators to apply the revised repair criteria to prior ILI assessments that, at the time, met all the standards of the regulations. Some of these commenters recommended PHMSA establish reasonable, risk-based timeframes for operators to implement repairs of anomalies that were historically identified and were repaired in accordance with the code requirements of the time. The GPAC, during their meeting in late March of 2018, similarly recommended that PHMSA add an effective date to these general repair provisions to clarify that they were not retroactive.

Some commenters also discussed the application of the proposed repair criteria to pipelines outside of HCAs that have established their MAOP under the alternative requirements at § 192.620. The GPAC recommended PHMSA apply appropriate predicted failure pressure factors to alternative MAOP pipelines based on class location and design factors for scheduled conditions under the repair criteria.

2. PHMSA Response

PHMSA did not intend for the new repair criteria for non-HCA pipe segments to be applicable to gas gathering pipelines, HCA segments, or offshore transmission lines. However, PHMSA will consider expanding the application of these provisions in the future. In this final rule, to clarify that the new non-HCA repair criteria apply only to onshore transmission lines, PHMSA placed the new non-HCA repair criteria in a new § 192.714, which applies only to onshore transmission lines. Subsequently, PHMSA withdrew all proposed changes to § 192.713. PHMSA has also revised § 192.9 in this final rule to exempt regulated gas gathering lines from the requirements of § 192.714. Additionally, PHMSA has modified § 192.711 in this final rule to clarify that the new repair criteria in § 192.714 do not apply to gathering lines or HCA segments subject to subpart O. The current and unchanged § 192.713 would continue to apply to regulated gas gathering lines. Although the creation of a new § 192.714 was not discussed at the GPAC, PHMSA determined that this approach was a clearer means to specify that the new non-HCA repair criteria only apply to onshore transmission pipelines and meet the intent of the GPAC recommendation to clarify that the non-HCA repair criteria do not apply to gathering lines, HCA segments, or offshore transmission lines. Furthermore, PHMSA determined that this approach avoids duplication of repair language in other code sections.

PHMSA did not intend to imply that the new repair criteria were to be applied retroactively and has clarified this intent in this final rule by revising § 192.711(b) to include an effective date as recommended by the GPAC.

Regarding alternative MAOP pipelines, the NPRM did not propose, and therefore did not give opportunity for comment on, changes to repair criteria for alternative MAOP pipe segments. However, PHMSA agrees with commenters that the language proposed in the NPRM could create ambiguity with respect to the applicability of the non-HCA repair criteria to pipe with MAOP established in accordance with § 192.620. Therefore, in this final rule, PHMSA more broadly exempted alternative MAOP lines from compliance with non-HCA repair criteria and reiterated the applicability of the repair criteria provided at the alternative MAOP provisions under § 192.620(d)(11) as they provide a comparable level of safety based upon the operating factors. PHMSA did not make a corresponding change to § 192.933, as alternative MAOP pipelines in HCAs must meet both the HCA and the alternative MAOP repair criteria. This approach is preferable to repeating the alternate MAOP repair criteria in two locations of part 192.

G. Definitions—§ 192.3

i. Close Interval Survey

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed a new definition for ''close interval survey'' as a series of closely spaced pipe-to-electrolyte potential measurements taken to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline and may cause corrosion, and for the purpose of quantifying voltage drops other than those across the structure electrolyte boundary.

2. Summary of Public Comment

Comments from the trade associations and GPAC members representing the industry questioned whether PHMSA should tie the definition of ''close interval survey'' to a corresponding NACE standard for consistency. PHMSA presented some minor changes to the definition at the meeting on March 28, 2018, and the committee voted 13–0 that PHMSA should adopt those changes into the final rule.

3. PHMSA Response

After considering the comments and GPAC recommendations, PHMSA is adopting the definition of ''close interval survey'' as recommended by GPAC. As such, PHMSA has specified that the pipe-to-electrolyte potential measurements are taken ''over the pipe,'' and added the phrase ''such as when performed as a current interrupted, depolarized, or native survey'' to qualify what is ''other than those across the structure electrolyte boundary.''

G. Definitions—§ 192.3

ii. Distribution Center

1. Summary of PHMSA's Proposal

PHMSA proposed to define a ''distribution center'' as a location where gas volumes are either metered or have a pressure or volume reduction prior to delivery to customers through a distribution line.

2. Summary of Public Comment

AGL Resources, Pipeline Safety Coalition, Southern California Gas

Company, Spire STL Pipeline LLC, and Xcel Energy supported PHMSA's intention to define the term ''distribution center.'' In particular, AGL Resources stated that the proposed definition would remove confusion and the potential for conflict between operators and regulators throughout the Nation. Like its comments on the proposed definition for ''transmission line,'' Xcel Energy suggested that PHMSA add an implementation period for operators to handle the regulatory impacts of the new definition.

AGA supported PHMSA's effort to define a ''distribution center'' to ensure consistency and certainty in the identification of transmission lines. However, AGA also stated that PHMSA failed to provide any justification or explanation for its proposed definition, and AGA proposed an alternative definition of ''distribution center'' where piping downstream of a distribution center that operates above 20 percent SMYS would be classified as a transmission line. Other organizations, such as Alliant Energy, Dominion Energy, PECO Energy, Paiute Pipeline Company, and Southwest Gas Corporation, supported AGA's alternative definition.

TPA recommended PHMSA revise the proposed definition of ''distribution center'' to provide a clear endpoint for transmission lines and the start of distribution lines. Atmos Energy stated that the proposed definition did not recognize the many possible configurations of pipes in which transmission pipelines deliver to distribution systems. For example, Oleksa and Associates stated that some distribution systems may have no meters prior to delivery to customers and also may have no pressure or volume reductions (*e.g.,* a distribution system supplied by a landfill). Lastly, Cascade Natural Gas requested the term ''distribution center'' clearly refer to distribution pipelines and that such a definition should not be included in a rulemaking for transmission and gathering pipelines.

At the GPAC meeting, PHMSA offered for the committee's consideration the option of recommending withdrawal of the proposed definition for ''distribution center.'' Committee members opposed this suggestion, stating that finalizing a definition for ''distribution center'' would provide the industry and regulators with regulatory certainty and clarity. During the meeting, committee members came to a consensus on the definition of a ''distribution center'' based on comments the industry provided. However, certain committee members representing the public were not inclined to adopt a definition of a ''distribution center'' that was based on the comments provided by industry and wished to defer to PHMSA regarding the wordsmithing of the definition.

Following the discussion, the committee voted 10–0 that the definition for ''distribution center'' was technically feasible, reasonable, cost-effective, and practicable if PHMSA incorporated a definition for ''distribution center'' in the final rule and considered revising the definition to mean the initial point where gas enters piping used to deliver gas to customers for end use as opposed to customers who purchase it for resale. Examples of a distribution center would include a metering location; a pressure reduction location; or where there is a reduction in the volume of gas, such as a lateral off a transmission pipeline.

3. PHMSA Response

After considering the comments received and the GPAC's recommendations, PHMSA is adopting the definition recommended by GPAC so that a ''distribution center'' means the initial point where gas enters piping used to deliver gas to customers for end use as opposed to customers who purchase it for resale.

PHMSA disagrees that an implementation period for the definition is appropriate, given that this term has been in use for a long period of time. PHMSA agrees with commenters for the need to clarify the end point of transmission and the start of distribution. PHMSA agrees with those commenters who suggested that piping downstream of a distribution center operating at above 20 percent SMYS should be considered a transmission line and is modifying the definition of ''transmission line'' accordingly in this final rule.

G. Definitions—§ 192.3

iii. Dry Gas or Dry Natural Gas

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed a new definition for the term ''dry gas or dry natural gas'' to mean gas with less than 7 pounds of water per million cubic feet that is not subject to excessive upsets allowing electrolytes into the gas system.

2. Summary of Public Comment

GPAC members representing the industry asked whether PHMSA should tie the definition for dry gas to the corresponding NACE standard for continuity. Committee members representing the public were concerned about incorporating by reference the definition into the regulations but were amenable to lifting the language directly from the standard to ensure consistency. PHMSA representatives noted that the agency could consider the NACE definition and make the definition for dry gas less prescriptive than proposed.

After discussion, the committee voted 13–0 that the definition for ''dry gas or dry natural gas'' was technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the definition to be consistent with the NACE definition as discussed at the meeting.

3. PHMSA Response

PHMSA has taken into consideration the comments as well as the GPAC recommendations and is modifying the definition for ''dry gas or dry natural gas'' to be consistent with the NACE standard. More specifically, the definition specifies that ''dry gas or dry natural gas'' is gas ''above its dew point and without condensed liquids.''

G. Definitions—§ 192.3

iv. Electrical Survey

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed revising the term ''electrical survey'' so that it means a series of closely spaced measurements of the potential difference between two reference electrodes to determine where the current is leaving the pipe on ineffectively coated or bare pipelines.

2. Summary of Public Comment

PHMSA received a variety of comments on the definition for ''electrical survey.'' Some commenters expressed support for the definition and its inclusion in the regulations. Other commenters supported the concept of the definition but provided PHMSA with varying edits to improve on the clarity and functionality of the definition.

Several commenters noted that the proposed definition for electrical survey was duplicative with the proposed definition for ''close interval survey'' and recommended that PHMSA retain the definition for close interval survey instead. Some of these commenters noted that the proposed definition for electrical survey was more restrictive than the definition of electrical survey in NACE standards and excluded certain types of surveys. Other commenters suggested that the proposed definition for electrical survey should match the definition in various NACE standards.

NACE itself believed that the definition used in the NPRM for

''electrical survey'' was ambiguous and inaccurate, stating the proposed definition does not align with current terminology and accepted pipeline integrity practices. NACE recommended that PHMSA use the definition for ''indirect inspection'' in NACE SP0502, which is widely accepted as standard practice and should meet PHMSA's intent.

The GPAC recommended that PHMSA withdraw the proposed changes to appendix D as a part of the recommended revisions to the proposed corrosion control regulations. There was no further discussion on the definition for the term, and the committee voted, 13–0, to delete the definition from the rule.

3. PHMSA Response

PHMSA notes that, when the committee voted to withdraw the proposed changes to appendix D as a part of the corrosion control discussion, a revised definition for electrical survey was unnecessary as all references to ''electrical surveys'' were removed. Therefore, PHMSA agrees with the GPAC recommendation and has struck the proposed revision to the definition of ''electrical survey'' from this final rule.

G. Definitions—§ 192.3

v. Hard Spot

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to define a ''hard spot'' as steel pipe material with a minimum dimension greater than 2 inches (50.8 mm) in any direction with hardness greater than or equal to Rockwell 35 HRC, Brinnel 327 HB, or Vickers 345 HV_{10}.

2. Summary of Public Comment

During the GPAC meeting, committee members noted there was a small editorial correction that needed to be made—changing ''Brinnel'' to ''Brinell'' —and also recommended that the definition be prefaced with the phrase ''an area on'' so that the definition reads ''an area on steel pipe material [. . .].''

3. PHMSA Response

PHMSA has modified the proposed definition of hard spot as the GPAC recommended for this final rule.

G. Definitions—§ 192.3

vi. In-Line Inspection (ILI) and In-Line Inspection Tool or Instrumented Internal Inspection Device

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to add definitions for ''in-line inspection (ILI)'' and ''in-line inspection tool or instrumental internal inspection device'' to § 192.3. Specifically, the term ''in-line inspection'' would mean the inspection of a pipeline from the interior of the pipe using an ILI tool, which may also be known as intelligent or smart pigging. The term ''in-line inspection tool or instrumented internal inspection device'' would mean a device or vehicle that inspects a pipeline from the inside using a non-destructive technique. Such a device might also be called an intelligent or smart pig.

2. Summary of Public Comment

NACE International commented that the proposed definitions of ''in-line inspection'' and ''in-line inspection tool or instrumented internal inspection device'' do not align with the definition provided in NACE International Standard SP01024 or SP0102, respectively. NACE International suggested that PHMSA use the definition in NACE Standard SP0102, as PHMSA had proposed to incorporate by reference the standard in the regulations.

The GPAC reviewed the proposed definitions and, following their discussion, voted 13–0 that the definitions for ''in-line inspection'' and ''in-line inspection tool or instrumented internal inspection device'' were technically feasible, reasonable, cost-effective, and practicable if PHMSA considered clarifying in the preamble that the phrase ''a line that can accommodate inspection by means of an instrumented in-line inspection tool'' referred to pipeline segments that can be inspected with free-swimming ILI tools without any permanent physical modification of the pipeline segment.

3. PHMSA Response

After considering these comments, PHMSA is modifying the definitions of both ''in-line inspection'' and ''in-line inspection tool or instrumented internal inspection device'' based on the definitions in NACE SP0102–2010. In accordance with the GPAC recommendation, PHMSA is also noting that an ILI can include both tethered and self-propelled (*i.e.,* ''free-swimming'') tools.

G. Definitions—§ 192.3

vii. Transmission Line

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to modify the second criterion of the ''transmission line'' definition to base the percentage of SMYS on the MAOP of the pipeline, whereas currently it is based on the pressure at which the pipeline is operating. PHMSA also proposed editorial changes to the ''Note'' section of the definition and make it clearer that ''factories, power plants, and institutional users of gas'' were examples of a large-volume customer.

2. Summary of Public Comment

AGA asserted that modifying the second criterion in the ''transmission line'' definition in conjunction with other definition changes PHMSA proposed would result in the reclassification of some transmission pipelines to distribution lines and some distribution pipelines to transmission lines. Several pipeline operators and industry representatives, including AGL Resources, Alliant Energy, Black Hills Energy, Cascade Natural Gas, Centerpoint Energy, Spire, Delmarva Power, National Grid, National Fuel Gas Supply Corporation, North Dakota Petroleum Council, Paiute Pipelines, TECO Peoples Gas, TPA, and PECO Energy, supported AGA's comments or provided similar recommendations. Additionally, Dominion East Ohio and Southwest Gas objected to PHMSA's proposed modifications to the definition, stating that the proposed definition would burden operators with ongoing IM programs with no additional benefit to public safety.

APGA commented that PHMSA's slight rewording of the note in the transmission definition regarding types of large-volume customers could be interpreted to mean that only factories, power plants, and institutional users of gas can be large-volume customers. APGA suggested PHMSA change the proposed language in the final rule to clarify that those listed items are examples of large-volume customers rather than a comprehensive list.

ONE Gas proposed an alternative simplified approach to the definition of ''transmission line'' that focuses on a line's MAOP as it relates to the percentage of yield strength.

There were various comments from other pipeline operators, including the suggestion that PHMSA remove the term ''distribution center'' from the definition of ''transmission line,'' allow operators to use MAOP to determine a transmission pipeline, and provide an implementation period for operators to incorporate regulatory requirements of the newly defined transmission lines.

During the GPAC meeting, committee members representing the industry expressed support for allowing operators to designate pipelines voluntarily as transmission lines, especially if their risk profile was high,

so that operators could operate and maintain those lines to a higher standard.

Following the discussion, the committee voted 10–0 that the definition for ''transmission line'' was technically feasible, reasonable, cost-effective, and practicable if PHMSA included the phrase ''an interconnected series of pipelines'' within the text of the definition and allowed operators to designate pipelines voluntarily as transmission lines.

3. PHMSA Response

PHMSA has considered the comments received regarding the proposed definition of a ''transmission line.'' PHMSA agrees with the recommendation from the GPAC to allow operators to designate pipelines voluntarily as transmission lines, as well as the recommendation from the GPAC to include the phrase ''an interconnected series of pipelines.'' Accordingly, PHMSA has revised the definition of ''transmission line'' in this final rule to include these recommendations.

PHMSA agrees with commenters that the language to clarify the examples of large-volume customers may imply a specific list and has withdrawn the changes to the note in the definition. In response to the comment on providing an implementation period for compliance with the new definition, PHMSA notes that it does not apply separate implementation periods to definitions outside of the effective date of the rule. If PHMSA determines that corresponding regulations would be affected by a change in a definition, it incorporates appropriate implementation time to those regulations as necessary.

PHMSA also notes that, per the comments received on the definition for ''distribution center,'' it agreed with commenters who suggested that piping downstream of a distribution center operating at above 20 percent of SMYS should be considered a transmission line and is modifying the definition of ''transmission line'' accordingly in this final rule.

PHMSA sees no functional difference in changing the definition of a transmission line from a pipeline that operators at a hoop stress of 20 percent or more of SMYS and a pipeline that has a MAOP of 20 percent or more of SMYS. For a pipeline to operate above 20 percent or more of SMYS, it will have an MAOP of 20 percent or more of SMYS. If an operator has a pipeline where the theoretical MAOP is higher than the pipeline's actual operating pressure, and therefore the line would need to be reclassified, the operator could reduce the MAOP of the line to keep the line's classification the same without affecting its operating pressure.

G. Definitions—§ 192.3

viii. Wrinkle Bend

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to define ''wrinkle bend'' as a bend in the pipe that was formed in the field during construction such that the inside radius of the bend has one or more ripples of various sizes or where the ratio of peaks to peaks or peaks to valleys are of a certain size, or where a mathematical equation could be substituted when a wrinkle bend's length cannot reliably be determined.

2. Summary of Public Comment

There was no significant public comment on this definition, and the GPAC recommended PHMSA adopt the definition as it was published in the NPRM.

3. PHMSA Response

PHMSA adopts the definition as it was published in the NPRM.

IV. Section-by-Section Analysis

Section 192.3 Definitions

Section 192.3 provides definitions for various terms used throughout part 192. In support of other regulations adopted in this final rule, PHMSA is amending the definition of ''transmission line'' and is adding new definitions for ''close interval survey,'' ''distribution center,'' ''dry gas or dry natural gas,'' ''hard spot,'' ''in-line inspection,'' ''in-line inspection tool or instrumented internal inspection device,'' and ''wrinkle bend.'' The definitions, including ''in-line inspection,'' ''dry gas or dry natural gas,'' and ''hard spot,'' clarify technical terms used in part 192 or in this rulemaking.

Section 192.7 What documents are incorporated by reference partly or wholly in this part?

Section 192.7 lists documents that are incorporated by reference in part 192. PHMSA is making conforming amendments to § 192.7 to include two NACE standard practice documents regarding SCCDA and ICDA.

Section 192.9 What requirements apply to gathering lines?

Section 192.9 lists the requirements that are applicable or not applicable to gathering lines. This final rule addresses several new requirements for transmission lines that are not intended to apply to gathering lines; PHMSA is adopting in this final rule revisions to § 192.9 to except each of offshore and Types A, B, and C [50] gas gathering lines from those requirements.

Section 192.13 What general requirements apply to pipelines regulated under this part?

Section 192.13 prescribes general requirements for gas pipelines. PHMSA has determined that public safety and environmental protection would be improved by requiring operators of transmission lines to evaluate and mitigate risks during all phases of the useful life of a pipeline as an integral part of managing pipeline design, construction, operation, maintenance, and integrity, including the MOC process.

As such, PHMSA has added a new paragraph (d) to § 192.13 with a general clause for transmission pipeline operators that invokes the requirements for the MOC process as it is outlined in ASME/ANSI B31.8S, section 11, and explicitly articulates the requirements for a MOC process applicable to onshore gas transmission pipelines. This final rule requires each operator to have a MOC process that must include the reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. While these general attributes of change management are already required for covered segments by virtue of the incorporation by reference of ASME/ANSI B31.8S, PHMSA believes it will improve the visibility and emphasis on these important program elements to require them for all onshore transmission pipelines directly in the rule text.

Section 192.18 How To Notify PHMSA

Section 192.18 in subpart A contains the procedure for an operator to submit notifications to PHMSA. Paragraph (c) has been modified to incorporate notification requirements for the use of ''other technology'' with external corrosion control and ICDA per §§ 192.461(g) and 192.927(b).[51] This is

[50] PHMSA notes that it has introduced in this final rule revisions to § 192.9(e), which paragraph was adopted in the Gas Gathering Final Rule, to identify specific provisions of part 192 that would apply to the new Type C category of part 192-regulated onshore gas gathering pipelines.

[51] PHMSA notes that between publication of this final rule and its effective date, regulatory amendments to § 191.18 adopted in rulemaking published in April 2022 will have been codified in the Code of Federal Regulations. ''Pipeline Safety:

Continued

consistent with the requirements PHMSA issued with the use of other technology for provisions finalized in the 2019 Gas Transmission Rule.

Section 192.319 Installation of Pipe in a Ditch

Section 192.319 prescribes requirements for installing pipe in a ditch, including requirements to protect pipe coating from damage during the process. Sometimes pipe coating is damaged during the construction process while it is being handled, lowered, and backfilled, which can compromise its ability to protect against external corrosion. Accordingly, this final rule adds new paragraphs (d) through (g) to § 192.319, which require that onshore gas transmission operators perform an above-ground indirect assessment to identify locations of suspected damage promptly after backfilling is completed and remediate coating damage. Mechanical damage is also detectable by these indirect assessment methods, since the forces that can mechanically damage steel pipe usually result in detectable coating defects.

If an operator uses ''other technology'' to perform an assessment required under this section, paragraph (e) requires the operator to notify PHMSA in accordance with § 192.18. Paragraph (g) requires each operator of transmission pipelines to make and retain, for the life of the pipeline, records documenting the coating assessment findings and repairs. The additional requirements of this section do not apply to gas gathering pipelines or distribution mains.

Section 192.461 External Corrosion Control: Protective Coating

Section 192.461 prescribes requirements for protective coating systems. Certain types of coating systems that have been used extensively in the pipeline industry can impede the process of cathodic protection if the coating disbonds from the pipe. Accordingly, this final rule amends paragraph (a)(4) to require that pipe coating has sufficient strength to resist damage during installation and backfill, and it also adds a new paragraph (f) to require that onshore gas transmission operators perform an above-ground indirect assessment to identify locations of suspected damage promptly after backfill is completed or anytime there is an indication that the coating might be compromised. To ensure the prompt remediation of any severe coating damage, new paragraph (h) requires operators create a remedial action plan and provides the specific timing requirements for repairs. New paragraph (g) requires an operator to notify PHMSA, in accordance with § 192.18, if using ''other technology'' for the coating assessment, and paragraph (i) specifies the documentation requirements for this section. The additional requirements of this section do not apply to gas gathering pipelines or distribution mains.

Section 192.465 External Corrosion Control: Monitoring

Section 192.465 requires that operators monitor CP and take prompt remedial action to correct deficiencies indicated by the monitoring. To clarify that regulatory requirement, this final rule amends paragraph (d) to require that operators of onshore transmission pipelines must complete remedial action no later than the next monitoring interval specified in § 192.465, within 1 year, or within 6 months of obtaining any permits, whichever is less.

This final rule also adds a new paragraph (f) to require onshore gas transmission operators to conduct annual test station readings to determine if CP is below the level of protection required in subpart I. For non-systemic or location-specific causes of insufficient CP, the operator must investigate and mitigate the cause. For insufficient CP due to systemic causes, an operator must complete CIS with the protective current interrupted, unless it is impractical to do so based on a geographical, technical, or safety reason. For example, issues related to cost would not be an adequate reason for not performing the survey, whereas performing a survey on a pipeline protected by direct buried sacrificial anodes (anodes directly connected to the pipelines) might be impractical. The revisions to paragraph (d) and new paragraph (f) do not apply to gas gathering lines or distribution mains.

Section 192.473 External Corrosion Control: Interference Currents

Interference currents can negate the effectiveness of CP systems. Section 192.473 currently prescribes general requirements to minimize the detrimental effects of interference currents. However, subpart I does not presently contain specific requirements to monitor and mitigate detrimental interference currents. Accordingly, this final rule adds a new paragraph (c) to require that onshore gas transmission operator corrosion control programs include interference surveys to detect the presence of interference currents when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced. Sources of stray current can include co-located pipelines, structures, HVAC power lines, new or enlarged power substations, new pipelines, and other structures. They can also include additional generation, a voltage uprating, and additional lines. The rule also requires operators perform remedial actions no later than 15 months after completing the interference survey, with an allowance for permitting, to protect the pipeline segment from detrimental interference currents. These additional requirements do not apply to gas gathering pipelines or distribution mains.

Section 192.478 Internal Corrosion Control: Monitoring

Section 192.477 prescribes requirements to monitor internal corrosion if corrosive gas is being transported. However, the existing rules do not prescribe operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system modifications, gas supply changes, upset conditions, or other changes. This could result in operators not identifying internal corrosion if an initial assessment did not identify the presence of corrosive gas. Accordingly, PHMSA has determined that additional requirements are needed to ensure that operators effectively monitor their gas stream quality to identify if, and when, corrosive gas is being transported and mitigate deleterious gas stream constituents (*e.g.,* contaminants or liquids).

Therefore, this final rule adds a new § 192.478 to require onshore gas transmission operators monitor for known deleterious gas stream constituents and evaluate gas monitoring data once every calendar year, not to exceed a period of 15 months. Additionally, this final rule adds a requirement for onshore gas transmission operators to review their internal corrosion monitoring and mitigation program annually, not to exceed 15 months, and adjust the program as necessary to mitigate the presence of deleterious gas stream constituents. These requirements are in addition to the existing requirements to check coupons or perform other methods to monitor for the actual

Requirement of Valve Installation and Minimum Rupture Detection Standards,'' 87 FR 20940 (Apr. 8, 2022) (identifying an effective date in October 2022) (Valve Installation Final Rule). The amendatory text at the end of this final rule, therefore, reflects the text of § 192.18 as it will be revised when the Valve Installation Final Rule becomes effective.

presence of internal corrosion in the case of transporting a known corrosive gas stream. The new § 192.478 does not apply to gas gathering pipelines or distribution mains.

Section 192.485 Remedial Measures: Transmission Lines

Section 192.485 prescribes requirements for operators to perform remedial measures to address general corrosion and localized corrosion pitting in transmission pipelines. For such conditions, the requirements specify that an operator may determine the strength of pipe based on actual remaining wall thickness by using the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3–805 (RSTRENG). PHMSA has determined that additional requirements are needed beyond ASME/ANSI B31G and RSTRENG to ensure such calculations have a sound basis and has revised § 192.485(c) to specify that an operator must calculate the remaining strength of the pipe in accordance with § 192.712, which prescribes important aspects such as pipe and material properties, assumptions allowed when data is unknown, accounting for uncertainties, and recordkeeping requirements.

Section 192.613 Continuing Surveillance

Extreme weather and natural disasters can affect the safe operation of a pipeline. Accordingly, this final rule revises § 192.613 to require operators to perform inspections after these events and take appropriate remedial actions.

Section 192.710 Transmission Lines: Assessments Outside of High Consequence Areas

Section 192.710 prescribes requirements for the periodic assessment of certain pipelines outside of HCAs. In the NPRM, PHMSA proposed for operators to use the non-HCA repair criteria being finalized in this rule if they performed an assessment on a non-HCA pipeline and discovered an anomaly requiring repair. However, in splitting the rulemaking, PHMSA finalized the assessment requirement in the 2019 Gas Transmission Final Rule but did not incorporate regulatory text establishing the corresponding repair criteria. Therefore, in this final rule, PHMSA has revised the assessment requirement at § 192.710 to require operators to use the repair criteria finalized in this rulemaking if anomalies are discovered during these assessments.

Section 192.711 Transmission Lines: General Requirements for Repair Procedures

Section 192.711 prescribes general requirements for repair procedures. For non-HCA segments, the existing regulations required that operators make permanent repairs as soon as feasible. However, no specific repair criteria were detailed, and no specific timeframe or pressure reduction requirements were provided. PHMSA has determined that more specific repair criteria are needed for pipelines not covered under the integrity management regulations. Such repair criteria will help to maintain safety in a consistent manner in Class 1 through Class 4 locations that may have significant populations but that are not HCAs. Accordingly, this final rule amends paragraph (b)(1) of § 192.711 to require operators remediate specific conditions, as defined in § 192.714, on non-HCA gas transmission pipelines. Paragraph (b)(1) retains the existing requirement that operators must repair anomalies on gathering pipelines regulated in accordance with § 192.9 as soon as feasible.

Section 192.712 Analysis of Predicted Failure Pressure and Critical Strain Levels

In the 2019 Gas Transmission Rule, PHMSA updated and codified minimum standards for determining the predicted failure pressure of pipelines containing anomalies or defects associated with corrosion metal loss and cracks. In this final rule, PHMSA is revising the repair criteria for gas transmission pipelines, including for dents. Some of the revised dent repair criteria allow operators to determine critical strain levels for dents and defer repairs if critical strain levels are not exceeded. As such, PHMSA has established minimum standards for operators to calculate critical strain levels in pipe with dent anomalies or defects and has included those standards in a new paragraph (c) of § 192.712. The title of this section has also been updated to reflect this addition. PHMSA has also provided reassessment schedules for engineering critical assessments that operators perform to determine maximum reevaluation intervals to ensure that anomalies do not grow to critical sizes.

Section 192.714 Transmission Lines: Permanent Field Repair of Imperfections and Damages

Section 192.713 prescribes requirements for the permanent repair of pipeline imperfections or damage that impairs the serviceability of steel transmission pipelines operating at or above 40 percent of SMYS. PHMSA has determined that more explicit requirements are needed in § 192.714 to identify criteria for the severity of imperfections or damage that must be repaired, and to identify the timeframe within which repairs must be made for pipelines in all class locations that are not in HCAs. Pipelines not in HCAs can still have significant populations that could be harmed by a pipeline leak or rupture. As such, PHMSA has determined that repair criteria should apply to any onshore transmission pipeline not covered under the IM regulations in subpart O. PHMSA believes that establishing these non-HCA segment repair conditions for Class 1 locations through Class 4 locations are important because, even though they are not within HCAs, these locations could be in highly populated areas and are not without consequence to public safety and the environment.

Accordingly, this final rule creates a new § 192.714 to establish repair criteria for immediate, 2-year, and monitored conditions that the operator must remediate or monitor to ensure pipeline safety. PHMSA is using the same criteria as it is issuing for HCAs, except conditions for which a 1-year response is required in HCAs will require a 2-year response in non-HCA pipeline segments so that operators can allocate their resources to HCAs on a higher-priority basis. Additionally, PHMSA is prescribing more explicit requirements for the *in situ* evaluation of cracks and crack-like defects using in-the-ditch tools whenever required, such as when an ILI, SCCDA, pressure test failure, or other assessment identifies anomalies that suggest the presence of such defects.

Section 192.911 What are the elements of an integrity management program?

Paragraph (k) of § 192.911 requires that IM programs include a MOC process as outlined in ASME/ANSI B31.8S, section 11. PHMSA has determined that specific attributes and features of the MOC process that are currently specified in ASME/ANSI B31.8S, section 11, should be codified directly within the text of subpart O for HCAs to make the requirements readily available to all operators of onshore gas transmission pipelines. This change is consistent with the new paragraph (d) in § 192.13 for all onshore transmission pipelines.

Section 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

Section 192.917 requires that operators with IM programs for covered pipeline segments identify potential threats to pipeline integrity and use the threat identification in their integrity program. This performance-based process includes requirements to identify threats to which the pipeline is susceptible, collect data for analysis, and perform a risk assessment. The regulations include special requirements for operators to address plastic pipe and particular threats, such as third-party damage and manufacturing and construction defects.

As specified in § 192.907(a), PHMSA expected operators to start with a framework for IM, which would later evolve into a more detailed and comprehensive program, and expected that an operator would continually improve its IM program as it learned more about the process and about the material condition of its pipelines through integrity assessments. PHMSA elaborated on this philosophy in the 2003 IM rule.[52]

Even though the IM regulations have been in effect since 2004, PHMSA still finds certain operators have poorly developed IM programs. The clarifications and additional specificity adopted in this final rule, with respect to the processes an operator must use in implementing the threat identification, risk assessment, and preventive and mitigative measure program elements, reflect PHMSA's expectation regarding the degree of progress operators should be making, or should have made, during the first 10 years of the implementation of the IM regulations.

The current IM regulations incorporate by reference ASME/ANSI B31.8S to require that operators implement specific attributes and features of the threat identification, data analysis, and risk assessment process in their IM programs. In this final rule, PHMSA is amending § 192.917 to insert certain critical features of ASME/ANSI B31.8S directly into the regulatory text. PHMSA is specifying several pipeline attributes that must be included in pipeline risk assessments and is explicitly requiring that operators integrate analyzed information and ensure that data is verified and validated to the maximum extent practical. To the degree that subjective data from SMEs must be used, PHMSA is requiring that an operator's program account and compensate for uncertainties in the risk model used and the data used in the operator's risk assessment. PHMSA is also in this final rule revising the non-exhaustive list of data to be collected for clarity or to eliminate redundant language.

PHMSA will note that in its advisory bulletin on the verification of records that ''verifiable'' records are those in which information is confirmed by other complementary, but separate, documentation. Such records might include contract specifications for a pressure test of a line segment complemented by field logs or purchase orders with pipe specifications verified by metallurgical tests of coupons pulled from the same pipe segment.

Additionally, PHMSA is clarifying the performance-based risk assessment aspects of the IM regulations in this final rule by specifying that operators must perform risk assessments that are adequate for evaluating the effects of interacting threats; determine additional P&M measures needed; analyze how a potential failure could affect HCAs, including the consequences of the entire worst-case incident scenario from initial failure to incident termination; identify the contribution to risk of each risk factor, or each unique combination of risk factors that interact or simultaneously contribute to risk at a common location; account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and evaluate risk reduction associated with candidate risk reduction activities, such as P&M measures.

In consideration of NTSB recommendation P–11–18, PHMSA is adopting regulations that require operators to validate their risk models considering incident, leak, and failure history and other historical information. These features are currently requirements because they are incorporated by reference in ASME/ANSI B31.8S. However, PHMSA has found that provisions incorporated directly into its regulatory text have higher levels of compliance. The final rule also amends the requirements for plastic pipe to provide specific examples of integrity threats for plastic pipe that must be addressed.

Section 192.923 How is direct assessment used and for what threats?

This final rule incorporates by reference NACE SP0206–2006, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas,'' for addressing ICDA, and NACE SP0204–2008, ''Stress Corrosion Cracking Direct Assessment,'' for addressing SCCDA. Accordingly, PHMSA has revised § 192.923(b)(2) and (3) to require operators comply with these standards.

Section 192.927 What are the requirements for using internal Corrosion Direct Assessment (ICDA)?

Section 192.927 specifies requirements for gas transmission pipeline operators who use ICDA for IM assessments. The requirements in § 192.927 were promulgated before NACE SP0206–2006 was published and require that operators follow ASME/ANSI B31.8S provisions related to ICDA. PHMSA has reviewed NACE SP0206–2006 and finds that it is more comprehensive and rigorous than either § 192.927 or ASME/ANSI B31.8S in many respects. Therefore, PHMSA is incorporating NACE SP0206–2006 into the regulations for the performance of ICDA and is establishing additional requirements for addressing covered segments within the technical process defined by the NACE standard.

This final rule requires that operators perform two direct examinations within each covered segment the first time ICDA is performed. These examinations are in addition to those required to comply with the NACE standard. The additional examinations are consistent with the current requirement in § 192.927(c)(5)(ii) that operators apply more restrictive criteria when conducting ICDA for the first time and are intending to verify, within the HCA, that the results of applying the process of NACE SP0206–2006 for the ICDA are acceptable. Applying the process for NACE SP0206–2006 requires more precise knowledge of the pipeline orientation (particularly slope) than operators may have in many cases. Conducting examinations within the HCA during the first application of ICDA will verify that applying the ICDA process provides an operator with adequate information about the covered segment. Operators who identify internal corrosion on these additional examinations, even though excavations at locations determined using NACE SP0206–2006 did not identify any internal corrosion, will know that improvements are needed to their knowledge of pipeline orientation. In addition, operators will know they need other adjustments to their application of the NACE standard to the covered segment for using ICDA in the future. Section 192.927(b) and (c) are revised in this final rule to address these issues.

PHMSA notes that, for these requirements, operators are prohibited from using assumed pipeline or operational data. Any data an operator

[52] ''Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)''; 68 FR 69778 (Dec. 15, 2003). See 68 FR 69789.

uses for its ICDA process should be based on known information, such as the pipeline route, the pipeline diameter, and pipeline flow inputs and outputs. Operators can choose to base their ICDA process on data that is more conservative than their known pipeline or operational data.

Section 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

Section 192.929 specifies requirements for gas transmission pipeline operators who use SCCDA for IM assessments. The requirements in § 192.929 were promulgated before NACE Standard Practice SP0204–2008 was published, and the standard requires that operators follow Appendix A3 of ASME/ANSI B31.8S. That appendix provides some guidance for conducting SCCDA but is limited to SCC that occurs in high-pH environments. Experience has shown that pipelines can also experience SCC degradation in areas where the surrounding soil has a pH near neutral (referred to as near-neutral SCC). NACE SP0204–2008 addresses near-neutral SCC as well as high-pH SCC. NACE SP0204–2008 also provides technical guidelines and process requirements that are both more comprehensive and rigorous for conducting SCCDA than § 192.929 or ASME/ANSI B31.8S.

Since NACE SP0204–2008 provides comprehensive guidelines on conducting SCCDA and is more comprehensive in scope than Appendix A3 of ASME/ANSI B31.8S, PHMSA has concluded the quality and consistency of SCCDA conducted under IM requirements would be improved by requiring operators to use NACE SP0204–2008. The final rule accomplishes this.

Section 192.933 What actions must be taken to address integrity issues?

Section 192.933 specifies injurious anomalies and defects that operators must remediate and the timeframes within which such remediation must occur. PHMSA determined that the existing regulations for repair criteria had gaps, as some injurious anomalies and defects were not listed as requiring remediation in a timely manner commensurate with their seriousness. To remedy this, in this final rule, PHMSA is designating the following types of defects as immediate conditions: (1) anomalies where the metal loss is greater than 80 percent of nominal wall thickness; (2) metal loss anomalies with a predicted failure pressure less than or equal to 1.1 times the MAOP; (3) a topside dent that has metal loss, cracking, or a stress riser; (4) anomalies where there is an indication of metal loss affecting certain longitudinal seams; and (5) cracks or crack-like anomalies meeting specified criteria.

The final rule also designates the following types of defects as 1-year conditions: (1) smooth topside dents with a depth greater than 6 percent of the pipeline diameter; (2) dents greater than 2 percent of the pipeline diameter that are located at a girth weld or spiral seam weld; (3) a bottom-side dent that has metal loss, cracking, or a stress riser; (4) metal loss anomalies where a calculation of the remaining strength of the pipe shows a predicted failure pressure ratio less than or equal to 1.39 for Class 2 locations, and 1.50 for Class 3 locations and Class 4 locations; (5) anomalies where there is metal loss that is at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld, and that has a predicted failure pressure less than 1.39 in Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, and less than 1.50 times the MAOP in all other Class 2 locations and all Class 3 and 4 locations; (6) anomalies where there is metal loss affecting a longitudinal seam; and (7) any indications of cracks or crack-like defects other than those listed as an immediate condition.

In this final rule, PHMSA is also adding requirements for addressing regulatory gaps related to the methods for calculating predicted failure pressure if metal loss exceeds 80 percent of wall thickness; time-sensitive integrity threats including corrosion affecting a longitudinal seam, especially those associated with seam types that are known to be susceptible to latent manufacturing defects, such as the failed pipe at San Bruno,[53] and selective seam weld corrosion; and the fact that the current regulations do not list SCC as an immediate condition even though it is listed in ASME/ANSI B31.8S as an immediate repair condition.

With respect to SCC, PHMSA has incorporated repair criteria to specify that operators must use engineering assessment techniques specified in § 192.712 to evaluate if cracks or crack-like anomalies should be categorized as an ''immediate'' condition, a ''1-year'' condition, or a ''monitored'' condition. PHMSA believes that this will help address NTSB recommendation P–12–3, which resulted from the investigation of the Enbridge accident near Marshall, MI.[54] Although the NTSB recommendation was specifically made for hazardous liquid pipelines regulated under part 195, SCC can affect gas transmission pipelines regulated under part 192 as well.

The current regulations do not include 1-year conditions for metal loss anomalies. For non-immediate conditions, the regulations direct operators to use Figure 4 in ASME/ANSI B31.8S to determine the repair criteria for metal loss anomalies that do not meet the ''immediate'' threshold. To address this gap, PHMSA is including certain metal loss anomalies in the list of 1-year conditions. These changes make the gas transmission repair criteria more consistent with the hazardous liquid repair criteria at 49 CFR 195.452(h).

PHMSA is also incorporating safety factors commensurate with the class location in which the pipeline is located to make 1-year conditions anomalies where the predicted failure pressure is less than or equal to 1.39 times MAOP in Class 2 locations, and 1.50 times MAOP in Class 3 and Class 4 locations in HCAs. Operators must continue to use ASME/ANSI B31.8S, Figure 4 for corrosion metal loss anomalies in Class 1 locations.

Additionally, the NTSB recommended that PHMSA revise the ''discovery of condition'' at 49 CFR 195.452(h)(2) to require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators notify PHMSA and provide an expected date when adequate information will become available.[55] PHMSA incorporated this NTSB recommendation into §§ 195.416(f) and 195.452(h)(2) of the ''Safety of Hazardous Liquid Pipelines'' final rule, which was published on October 1, 2019.[56]

Although the NTSB made the recommendation for hazardous liquid pipelines regulated under part 195, the issue applies to gas transmission pipelines regulated under part 192 as well. Accordingly, PHMSA has

[53] These seam types include seams formed by direct current, low- or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is less than 1.25 times the MAOP.

[54] See NTSB Recommendation P–12–3, available at *https://www.ntsb.gov/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-12-003.*

[55] NTSB Recommendation P–12–4, available at *https://www.ntsb.gov/safety/safety-recs/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-12-004.*

[56] See 84 FR 52260.

amended paragraph (b) of § 192.933 to require that operators notify PHMSA whenever the operator cannot obtain sufficient information to determine if a condition presents a potential threat to the integrity of the pipeline within 180 days of completing the assessment.

PHMSA is also finalizing requirements for the *in situ* evaluation of cracks and crack-like defects using in-the-ditch tools whenever an operator discovers conditions that need to be repaired, such as when an ILI, an SCCDA, a pressure test failure, or another assessment identifies such anomalies. This applies to IM pipelines the same requirement adopted in § 192.714(g) for non-IM pipelines.

Section 192.935 What additional preventive and mitigative measures must an operator take?

Section 192.935 requires an operator to take additional measures beyond those already required by part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in an HCA. An operator must conduct a risk analysis to identify the additional measures to protect the HCA and improve public safety. As discussed earlier, PHMSA is amending § 192.917 to clarify the guidance for risk analyses operators use to evaluate and select additional P&M measures. This final rule also adds specific enhanced measures for operators to use for managing internal and external corrosion in HCAs and expands the list of P&M measures operators must consider when providing for public safety.

Specifically, operators must explicitly consider the following P&M measures:

(i) Correcting the root causes of past incidents in order to prevent recurrence;
(ii) O&M processes that maintain safety and the pipeline MAOP;
(iii) Adequate resources for the successful execution of these activities within the required timeframe;
(iv) Pressure transmitters that communicate with the pipeline control center on both sides of automatic shut-off valves and remote-control valves;
(v) Additional right-of-way patrols;
(vi) Hydrostatic tests in areas where pipeline material has quality issues or records that are not traceable, verifiable, and complete;
(vii) Tests to determine unknown material, mechanical, or chemical properties that are needed to ensure pipeline integrity or substantiate MAOP, including material property tests from removed pipe that is representative of the in-service pipeline;
(viii) The re-coating of damaged, poorly performing, or disbonded coatings, and
(ix) Additional depth-of-cover surveys at roads, streams, and rivers, among other areas.

These P&M measures do not alter the fundamental requirement for operators to identify and implement P&M measures; rather, they provide additional guidance and clarify PHMSA's expectations with this important aspect of IM.

Section 29 of the 2011 Pipeline Safety Act requires operators to consider seismicity when evaluating threats. In the 2019 Gas Transmission Rule, PHMSA revised § 192.917 to include seismicity as a potential threat for operators to identify and evaluate. In this final rule, PHMSA is revising this section to require operators consider the seismicity of the area when evaluating additional P&M measures against the threat of outside force damage.

Section 192.941 What is a low stress reassessment?

Section 192.941 specifies that, to address the threat of external corrosion on cathodically protected pipe in an HCA segment, an operator must perform an electrical survey (*i.e.,* with an indirect examination tool or method) at least every 7 years. In this final rule, PHMSA is replacing the term ''electrical survey'' with ''indirect assessment'' to accommodate other techniques that are comparably effective.

V. Standards Incorporated by Reference

A. Summary of New and Revised Standards

Consistent with the amendments in this document, PHMSA is incorporating by reference into the PSR several standards as described below. Some of these standards are already incorporated by reference into the PSR and are being extended to other sections of the regulations. Other standards provide a technical basis for corresponding regulatory changes in this final rule.

• NACE Standard Practice 0204–2008, ''Stress Corrosion Cracking (SCC) Direct Assessment Methodology'' (Sept. 18, 2008).

This standard addresses the situation in which a portion of a pipeline has been identified as an area of interest with respect to SCC based on its history, operations, and risk assessment process, and it has been decided that direct assessment is an appropriate approach for integrity assessment. The incorporation of this standard into the PSR would provide guidance for managing SCC through the selection of potential pipeline segments, selecting dig sites within those segments, inspecting the pipe, collecting and analyzing data during the dig, establishing a mitigation program, defining the re-evaluation interval, and evaluating the effectiveness of the SCCDA process.

• NACE Standard Practice 0206–2006, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas'' (DG–ICDA) (Dec. 1, 2006).

This standard practice formalizes an internal corrosion direct assessment method (DG–ICDA) that can be used to help ensure pipeline integrity for pipelines carrying normally dry natural gas. The method is applicable to natural gas pipelines that normally carry dry gas but that may suffer from infrequent, short-term upsets of liquid water (or other electrolyte). This standard is intended for use by pipeline operators and others who manage pipeline integrity. The basis of DG–ICDA is a detailed examination of locations along a pipeline where water would first accumulate and provides information about the downstream condition of the pipeline. If the locations along a length of pipe most likely to accumulate water have not corroded, other downstream locations less likely to accumulate water may be considered free from corrosion. The presence of extensive corrosion found at many locations during the evaluation suggests that the transported gas was not normally dry, and this standard would not be considered applicable.

• ASME/ANSI B31.8S–2004, ''Supplement to B31.8 on Managing System Integrity of Gas Pipelines'' (Jan. 14, 2005).

This standard covers onshore gas pipeline systems constructed with ferrous materials, including pipe, valves, appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. ASME/ANSI B31.8S is specifically designed to provide the operator with the information necessary to develop and implement an effective IM program using proven industry practices and processes. Effective system management can decrease repair and replacement costs, prevent malfunctions, and minimize system downtime.

The incorporation by reference of ASME/ANSI B31.8S–2004 was approved for §§ 192.921 and 192.937 as of January 14, 2004. That approval is unaffected by the section revisions in this final rule.

• ANSI/NACE Standard Practice 0502–2010, ''Pipeline External Corrosion Direct Assessment Methodology'' (June 24, 2010).

This standard covers the NACE external corrosion direct assessment (ECDA) process, which assesses and

reduces the impact of external corrosion on pipeline integrity. ECDA is a continuous-improvement process providing the advantages of locating areas where defects can form in the future, not just areas where defects have already formed, thereby helping to prevent future external corrosion damage. This standard covers the four components of ECDA: Pre-Assessment, Indirect Inspections, Direct Examinations, and Post-Assessment.

The incorporation by reference of ANSI/NACE Standard Practice 0502–2010 was approved for §§ 192.923, 192.925, 192.931, 192.935, and 192.939 as of March 6, 2015. That approval is unaffected by the section revisions in this final rule.

The incorporation by reference of R–STRENG and ASME/ANSI B31G in certain sections of this rule was approved July 1, 2020, and remains unaffected by the revisions in this final rule.

B. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 80 standards and specifications developed and published by standard developing organizations (SDO). In general, SDOs update and revise their published standards every 2 to 5 years to reflect modern technology and best technical practices.

The National Technology Transfer and Advancement Act of 1995 (Pub. L. 104–113; NTTAA) directs Federal agencies to use standards developed by voluntary consensus standards bodies in lieu of government-written standards whenever possible. Voluntary consensus standards bodies develop, establish, or coordinate technical standards using agreed-upon procedures. In addition, the Office of Management and Budget (OMB) issued Circular A–119 to implement section 12(d) of the NTTAA relative to the utilization of consensus technical standards by Federal agencies.[57] This circular provides guidance for agencies participating in voluntary consensus standards bodies and describes procedures for satisfying the reporting requirements in the NTTAA.

Accordingly, PHMSA has the responsibility for determining, via petitions or otherwise, which currently referenced standards should be updated, revised, or removed, and which standards should be added to the PSR. Revisions to materials incorporated by reference in the PSR are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

Pursuant to 49 U.S.C. 60102(p), PHMSA may not issue PSR amendments that incorporate by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge. Further, the Office of the Federal Register issued a rulemaking on November 7, 2014, revising 1 CFR 51.5(b) to require that agencies detail in the preamble of a final rulemaking the ways the materials it incorporates by reference are reasonably available to interested parties, and how interested parties can obtain those materials.[58]

To meet its statutory obligation for this rulemaking, PHMSA negotiated agreements with SDOs to provide free online access to standards that are incorporated by reference or proposed to be incorporated by reference. PHMSA will also provide individual members of the public temporary access to any standard that is incorporated by reference. Requests for access can be sent to the following email address: *phmsaphpstandards@dot.gov;* please include your phone number, physical address, and an email address and PHMSA will respond within 5 business days and provide access to the standard. PHMSA also notes that standards incorporated by reference in the PSR can be obtained from the organization developing each standard. Section 192.7 provides the contact information for each of those standard-developing organizations.

VI. Regulatory Analysis and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the existing authorities of the Secretary of Transportation delegated to the PHMSA Administrator pursuant to 49 CFR 1.97. Among the statutory authorities delegated to PHMSA are section 60102 of the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*) (authorizing issuance of regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities) and section 28 of the Mineral Leasing Act, as amended (30 U.S.C. 185(w)(3)). For a complete listing of authorities, see 49 CFR 1.97.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

Executive Order 12866 (''Regulatory Planning and Review'')[59] requires that agencies ''should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating.'' Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify. Further, Executive Order 12866 requires that agencies ''should maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach.'' Similarly, DOT Order 2100.6A (''Rulemaking and Guidance Procedures'') requires that regulations issued by PHMSA and other DOT Operating Administrations should consider an assessment of the potential benefits, costs, and other important impacts of the proposed action and should quantify (to the extent practicable) the benefits, costs, and any significant distributional impacts, including any environmental impacts. The Federal Pipeline Safety Statutes at 49 U.S.C. 60102(b)(5) further authorize only those safety requirements whose benefits (including safety and environmental benefits) have been determined to justify their costs.

This action has been determined to be significant under Executive Order 12866. It is also considered significant under DOT Order 2100.6A because of significant congressional, State, industry, and public interest in pipeline safety. The final rule has been reviewed by the Office of Management and Budget in accordance with Executive Order 12866 and is consistent with the requirements of Executive Order 12866, 49 U.S.C. 60102(b)(5), and DOT Order 2100.6. The Office of Information and Regulatory Affairs (OIRA) has not designated this rule as a ''major rule'' as defined by the Congressional Review Act (5 U.S.C. 801 *et seq.*).

Executive Order 12866 and DOT Order 2100.6A also require PHMSA to provide a meaningful opportunity for public participation, which also reinforces requirements for notice and comment under the Administrative Procedure Act (5 U.S.C. 551 *et seq.*). Therefore, in the NPRM, PHMSA sought public comment on its proposed revisions to the PSR and the preliminary cost and benefit analyses in the PRIA, as

[57] 81 FR 4673 (Jan. 27, 2016).

[58] 79 FR 66278.

[59] 58 FR 51735 (Oct. 4, 1993).

well as any information that could assist in quantifying the costs and benefits of this rulemaking. Those comments are addressed in this final rule, and additional discussion about the costs and benefits of the final rule are provided within the RIA posted in the rulemaking docket.

The table below summarizes the annualized costs for the provisions in the final rule. These estimates reflect the timing of the compliance actions taken by operators and are annualized, where applicable, over 20 years and discounted using rates of 3 percent and 7 percent. PHMSA estimates incremental costs for the final requirements in section 5 of the RIA. The costs of this final rule reflect MOC process improvements, additional corrosion control requirements, programmatic changes related to inspections following extreme weather events, and compliance with the revised repair criteria. PHMSA finds that the other final rule requirements will not result in an incremental cost. PHMSA estimates the annualized cost of this rule is $16.7 million at a 7 percent discount rate.

TABLE 1—ANNUALIZED COST OF THE FINAL RULE, YEAR 1–YEAR 20

[$2019 USD thousands]

Provision	Discount rate	
	3%	7%
Integrity Management Process Improvements *	$0	$0
Management of Change Process Improvements	1,194	1,223
Corrosion Control	8,662	8,998
Extreme Weather	55	78
Repair Criteria	2,725	6,357
Total	12,637	16,656

* No incremental costs are estimated for this topic area.

The benefits of the final rule consist of improved safety and avoided environmental harms (including greenhouse gas emissions) from reduction of risk of incidents on natural gas pipelines and will depend on the degree to which compliance actions result in additional safety measures, relative to the baseline, and the effectiveness of these measures in preventing or mitigating future pipeline releases or other incidents. PHMSA changed its benefit analysis approach for the RIA relative to the PRIA. The PRIA quantified and monetized the NPRM's benefits, while the RIA does not monetize this final rule's benefits. PHMSA chose not to monetize benefits in the RIA based on the public comments received in response to the PRIA and the uncertainty associated with quantifying changes in incident rates that can be explicitly attributed to the final rule's provisions.

For more information, please see the RIA posted in the rulemaking docket.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires agencies to prepare a Final Regulatory Flexibility Analysis (FRFA) for any final rule subject to notice-and-comment rulemaking under the APA unless the agency head certifies that the rule will not have a significant economic impact on a substantial number of small entities. This final rule was developed in accordance with Executive Order 13272 (''Proper Consideration of Small Entities in Agency Rulemaking'')[60] to promote compliance with the Regulatory Flexibility Act and to ensure that the potential impacts of the rulemaking on small entities has been properly considered.

PHMSA prepared a FRFA, which is available in the docket for the rulemaking. In it, PHMSA certifies that the rule will not have a significant impact on a substantial number of small entities.

D. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA analyzed this final rule per the principles and criteria in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments'')[61] and DOT Order 5301.1 (''Department of Transportation Policies, Programs, and Procedures Affecting American Indians, Alaska Natives, and Tribes''). Executive Order 13175 requires agencies to assure meaningful and timely input from Tribal Government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing ''substantial direct compliance costs'' or ''substantial direct effects'' on such communities or the relationship and distribution of power between the Federal Government and Tribes.

PHMSA assessed the impact of the rulemaking and determined that it would not significantly or uniquely affect Tribal communities or Tribal governments. The rulemaking's regulatory amendments are facially neutral and would have broad, national scope; PHMSA, therefore, does not expect this rulemaking to significantly or uniquely affect Tribal communities, much less impose substantial compliance costs on Native American Tribal governments or mandate Tribal action. And insofar as PHMSA expects the rulemaking will improve transmission pipeline safety and environmental risks, PHMSA does not expect it would entail disproportionately high adverse risks for Tribal communities. PHMSA also received no comments alleging ''substantial direct compliance costs'' or ''substantial direct effects'' on Tribal communities and Governments. For these reasons, PHMSA has determined the funding and consultation requirements of Executive Order 13175 and DOT Order 5301.1 do not apply.

E. Paperwork Reduction Act

Under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), no person is required to respond to an information collection unless it has been approved by OMB and displays a valid OMB control number. Pursuant to implementing regulations at 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests.

On April 8, 2016, PHMSA published an NPRM seeking public comments on proposed revisions of the PSR

[60] 68 FR 7990 (Feb. 19, 2003).

[61] 65 FR 67249 (Nov. 6, 2000).

applicable to the safety of gas transmission pipelines and gas gathering pipelines. Based on the provisions in the NPRM, PHMSA proposed corresponding changes to information collections. PHMSA determined it would be more effective to first advance a rulemaking that focused on the mandates from the 2011 Pipeline Safety Act and subsequently split out the other provisions contained in the NPRM into three separate rules. As such, in this rulemaking, PHMSA has removed all references to the changes in the information collections covered in those other rulemakings. PHMSA will submit information collection revision requests to OMB based on the requirements contained within this final rule.

PHMSA estimates that the proposals in this final rule will involve new and amended information collections as described below. The following information is provided for each information collection: (1) title of the information collection; (2) OMB control number; (3) current expiration date; (4) type of request; (5) abstract of the information collection activity; (6) description of affected public; (7) estimate of total annual reporting and recordkeeping burden; and (8) frequency of collection. Relevant information collections consist of the following:

1. Title: Record Keeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 3/31/2025.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation upon request. Based on the proposed revisions in this final rule, 16 new recordkeeping requirements are being added to the pipeline safety regulations for owners and operators of gas transmission pipelines. PHMSA expects these new mandatory recordkeeping requirements to result in 1,902 responses and 9,530 burden hours.

Affected Public: Gas Transmission Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,863,374.

Total Annual Burden Hours: 1,686,560.

Frequency of Collection: On occasion.

2. Title: Notification Requirements for Gas Transmission Pipelines.

OMB Control Number: 2137–0636.

Current Expiration Date: 01/31/2023.

Abstract: A person owning or operating a natural gas pipeline facility is required to provide information to the Secretary of Transportation at the Secretary's request in accordance with 49 U.S.C. 60117. The regulations in 49 CFR part 192 require operators to make various notifications upon the occurrence of certain events. Based on the proposed revisions in this final rule, 6 new notification requirements are being added to the PSR for owners and operators of gas transmission pipelines. PHMSA expects these revisions to result in 268 additional responses and 290 additional burden hours for this information collection. These mandatory notification requirements are necessary to ensure safe operation of transmission pipelines, ascertain compliance with gas pipeline safety regulations, and to provide a background for incident investigations.

Affected Public: Gas Transmission Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 990.

Total Annual Burden Hours: 1,360.

Frequency of Collection: On occasion.

3. Title: Annual Reports for Gas Pipeline Operators

OMB Control Number: 2137–0522.

Current Expiration Date: 3/31/2025.

Abstract: This information collection covers the collection of annual report data from natural gas pipeline operators. PHMSA is revising the Gas Transmission and Gas Gathering Annual Report (form PHMSA F7 100.2–1) to collect more granular data on conditions being repaired outside of HCA segments. Operators currently provide the number of anomalies outside of HCAs based on assessment methods, however, PHMSA requires operators to further categorize the data in accordance with 49 CFR 192.713. Based on the proposed revisions, PHMSA estimates that it will take an additional 30 minutes per report to include the newly required data—increasing the burden for completing each annual report to 47.5 hours. This change results in an overall burden increase of 905 hours for this information collection.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,053.

Total Annual Burden Hours: 95,521.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue, SE, Washington, DC 20590–0001, Telephone (202) 366–4595.

F. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, and the private sector. For any NPRM or final rule that includes a Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector of $100 million or more in 1996 dollars in any given year, the agency must prepare, amongst other things, a written statement that qualitatively and quantitatively assesses the costs and benefits of the Federal mandate.

As explained in the RIA, PHMSA determined that this final rule does not impose enforceable duties on State, local, or Tribal governments or on the private sector of $100 million or more (in 1996 dollars) in any one year. A copy of the RIA is available for review in the docket.

G. National Environmental Policy Act

The National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*, NEPA), requires Federal agencies to consider the consequences of major Federal actions and prepare a detailed statement on actions significantly affecting the quality of the human environment. The Council on Environmental Quality implementing regulations (40 CFR parts 1500–1508) require Federal agencies to conduct an environmental review considering (1) the need for the action, (2) alternatives to the action, (3) probable environmental impacts of the action and alternatives, and (4) the agencies and persons consulted during the consideration process. DOT Order 5610.1C (''Procedures for Considering Environmental Impacts'') establishes departmental procedures for evaluation of environmental impacts under NEPA and its implementing regulations.

PHMSA has completed its NEPA analysis. Based on the environmental assessment, PHMSA determined that an environmental impact statement is not required for this rulemaking because it will not have a significant impact on the human environment. The final EA and Finding of No Significant Impact have been placed into the docket addressing the comments received.

H. Executive Order 13132

PHMSA analyzed this final rule in accordance with Executive Order 13132 (''Federalism'').[62] Executive Order

[62] 64 FR 43255 (Aug.10, 1999).

13132 requires agencies to assure meaningful and timely input by State and local officials in the development of regulatory policies that may have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

The final rule does not have a substantial direct effect on the State and local governments, the relationship between the Federal Government and the States, or the distribution of power and responsibilities among the various levels of government. This rulemaking action does not impose substantial direct compliance costs on State and local governments. Section 60104(c) of the Federal Pipeline Safety Statutes prohibits certain State safety regulation of interstate pipelines. Under the Federal Pipeline Safety Statutes, States can augment pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate. In this instance, the preemptive effect of the final rule is limited to the minimum level necessary to achieve the objectives of the pipeline safety laws under which the final rule is promulgated. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

I. Executive Order 13211

Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'')[63] requires Federal agencies to prepare a Statement of Energy Effects for any ''significant energy action.'' Executive Order 13211 defines a ''significant energy action'' as any action by an agency (normally published in the **Federal Register**) that promulgates, or is expected to lead to the promulgation of, a final rule or regulation that (1)(i) is a significant regulatory action under Executive Order 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy (including a shortfall in supply, price increases, and increased use of foreign supplies); or (2) is designated by the Administrator of the OIRA as a significant energy action.

This final rule is a significant action under Executive Order 12866; however, it is expected to have an annual effect on the economy of less than $100 million. Further, this action is not likely to have a significant adverse effect on the supply, distribution, or use of energy in the United States. The Administrator of OIRA has not designated the final rule as a significant energy action. For additional discussion of the anticipated economic impact of this rulemaking, please review the RIA posted in the rulemaking docket.

J. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement[64] at: *https://www.govinfo.gov/content/pkg/FR-2000-04-11/pdf/00-8505.pdf.*

K. Executive Order 13609 and International Trade Analysis

Executive Order 13609 (''Promoting International Regulatory Cooperation'')[65] requires agencies consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements.

Similarly, the Trade Agreements Act of 1979 (Pub. L. 96–39), as amended by the Uruguay Round Agreements Act (Pub. L. 103–465), prohibits Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. For purposes of these requirements, Federal agencies may participate in the establishment of international standards, so long as the standards have a legitimate domestic objective, such as providing for safety, and do not operate to exclude imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards.

PHMSA participates in the establishment of international standards to protect the safety of the American public. PHMSA has assessed the effects of the rulemaking and determined that it will not cause unnecessary obstacles to foreign trade.

L. Environmental Justice

DOT Order 5610.2(b) and Executive Orders 12898 (''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations''),[66] 13985 (''Advancing Racial Equity and Support for Underserved Communities Through the Federal Government''),[67] 13990 (''Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis''),[68] and 14008 (''Tackling the Climate Crisis at Home and Abroad'')[69] require DOT operational administrations to achieve environmental justice as part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects, including interrelated social and economic effects, of their programs, policies, and activities on minority populations, low-income populations, and other underserved disadvantaged communities.

PHMSA has evaluated this final rule under DOT Order 5610.2(b) and the Executive Orders listed above and determined it would not cause disproportionately high and adverse human health and environmental effects on minority populations, low-income populations, and other underserved and disadvantaged communities. The rulemaking is facially neutral and national in scope; it is neither directed toward a particular population, region, or community, nor is it expected to adversely impact any particular population, region, or community. And insofar as PHMSA expects the rulemaking would reduce the safety and environmental risks associated with natural gas transmission pipelines, many of which are located in the vicinity of environmental justice communities,[70] PHMSA expects the regulatory amendments introduced by this final rule would reduce adverse human health and environmental risks for minority populations, low-income populations, and other underserved and other disadvantaged communities in the vicinity of those pipelines. Lastly, as

[63] 66 FR 28355 (May 18, 2001).

[64] 65 FR 19476 (Apr. 11, 2000).

[65] 77 FR 26413 (May 4, 2012).

[66] 59 FR 7629 (Feb. 16, 1994).

[67] 86 FR 7009 (Jan. 20, 2021).

[68] 86 FR 7037 (Jan. 20, 2021).

[69] 86 FR 7619 (Feb. 1, 2021).

[70] See Ryan Emmanuel, et al., ''Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States,'' 5:6 GeoHealth (June 2021), *https://agupubs.onlinelibrary.wiley.com/toc/24711403/2021/5/6* (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

explained in the final EA, PHMSA expects that the regulatory amendments in this final rule will yield GHG emissions reductions, thereby reducing the risks posed by anthropogenic climate change to minority, low-income, underserved, and other disadvantaged populations and communities.

List of Subjects in 49 CFR Part 192

Corrosion control, Incorporation by reference, Installation of pipe in a ditch, Integrity management, Internal inspection device, Management of change, Pipeline safety, Repair criteria, Surveillance.

In consideration of the foregoing, PHMSA amends 49 CFR part 192 as follows:

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 1. The authority citation for part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et seq.,* and 49 CFR 1.97.

■ 2. In § 192.3:
■ a. Add definitions for ''Close interval survey'', ''Distribution center'', ''Dry gas or dry natural gas'', ''Hard spot'', ''In-line inspection (ILI)'', and ''In-line inspection tool or instrumented internal inspection device'' in alphabetical order;
■ b. Revise the definition for ''Transmission line''; and
■ c. Add the definition ''Wrinkle bend'' in alphabetical order.

The additions and revision read as follows:

§ 192.3 Definitions.

* * * * *

Close interval survey means a series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey.

* * * * *

Distribution center means the initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption, as opposed to customers who purchase it for resale, for example:

(1) At a metering location;

(2) A pressure reduction location; or

(3) Where there is a reduction in the volume of gas, such as a lateral off a transmission line.

* * * * *

Dry gas or dry natural gas means gas above its dew point and without condensed liquids.

* * * * *

Hard spot means an area on steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinell 327 HB or Vickers 345 HV_{10}).

* * * * *

In-line inspection (ILI) means an inspection of a pipeline from the interior of the pipe using an inspection tool also called *intelligent* or *smart pigging.* This definition includes tethered and self-propelled inspection tools.

In-line inspection tool or *instrumented internal inspection device* means an instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside in order to identify and characterize flaws to analyze pipeline integrity; also known as an *intelligent* or *smart pig.*

* * * * *

Transmission line means a pipeline or connected series of pipelines, other than a gathering line, that:

(1) Transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center;

(2) Has an MAOP of 20 percent or more of SMYS;

(3) Transports gas within a storage field; or

(4) Is voluntarily designated by the operator as a transmission pipeline.

Note 1 to *transmission line.* A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

* * * * *

Wrinkle bend means a bend in the pipe that:

(1) Was formed in the field during construction such that the inside radius of the bend has one or more ripples with:

(i) An amplitude greater than or equal to 1.5 times the wall thickness of the pipe, measured from peak to valley of the ripple; or

(ii) With ripples less than 1.5 times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under 12.

(2)(i) If the length of the wrinkle bend cannot be reliably determined, then wrinkle bend means a bend in the pipe where (h/D)*100 exceeds 2 when S is less than 37,000 psi (255 MPa), where (h/D)*100 exceeds for psi [for MPa] when S is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where (h/D)*100 exceeds 1 when S is 47,000 psi (324 MPa) or more.

(ii) Where:

(A) D = Outside diameter of the pipe, in. (mm);

(B) h = Crest-to-trough height of the ripple, in. (mm); and

(C) S = Maximum operating hoop stress, psi (S/145, MPa).

■ 3. In § 192.7:
■ a. Revise paragraphs (a) and (c)(6);
■ b. Redesignate paragraph (h)(1) as paragraph (h)(4) and paragraph (h)(2) as paragraph (h)(1);
■ c. Add new paragraph (h)(2) and paragraph (h)(3); and
■ d. Revise newly redesignated paragraph (h)(4).

The revisions and additions read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All approved material is available for inspection at the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590, 202–366–4046, *https://www.phmsa.dot.gov/pipeline/regs,* and at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email *fr.inspection@nara.gov,* or go to *www.archives.gov/federal-register/cfr/ibr-locations.html.* It is also available from the sources in the following paragraphs of this section.

* * * * *

(c) * * *

(6) ASME/ANSI B31.8S–2004, ''Supplement to B31.8 on Managing System Integrity of Gas Pipelines,'' approved January 14, 2005, (ASME/ANSI B31.8S), IBR approved for §§ 192.13(d); 192.714(c) and (d); 192.903 note to *potential impact radius;* 192.907 introductory text and (b); 192.911 introductory text, (i), and (k) through (m); 192.913(a) through (c); 192.917(a) through (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b) and (c); 192.929(b); 192.933(c) and (d); 192.935(a) and (b); 192.937(c); 192.939(a); and 192.945(a).

* * * * *

(h) * * *

(2) NACE SP0204–2008, Standard Practice, ''Stress Corrosion Cracking (SCC) Direct Assessment Methodology,'' reaffirmed September 18, 2008, (NACE SP0204); IBR approved for §§ 192.923(b); 192.929(b) introductory text, (b)(1) through (3), (b)(5) introductory text, and (b)(5)(i).

(3) NACE SP0206–2006, Standard Practice, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG–ICDA),'' approved December 1, 2006, (NACE SP0206), IBR approved for §§ 192.923(b); 192.927(b), (c) introductory text, and (c)(1) through (4).

(4) ANSI/NACE SP0502–2010, Standard Practice, ''Pipeline External Corrosion Direct Assessment Methodology,'' revised June 24, 2010, (NACE SP0502), IBR approved for §§ 192.319(f); 192.461(h); 192.923(b); 192.925(b); 192.931(d); 192.935(b); and 192.939(a).

* * * * *

■ 4. In § 192.9, paragraphs (b), (c), (d)(1) and (2), and (e)(1)(i) and (ii) are revised to read as follows:

§ 192.9 What requirements apply to gathering pipelines?

* * * * *

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, and 192.714 and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c) 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, and 192.714 and in subpart O of this part. However, an operator of a Type A regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N of this part by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) * * *

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.179(e) and (f), 192.205, 192.227(c), 192.285(e), 192.319(d) through (g), 192.506, 192.634, and 192.636 is not required;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines, except the requirements in §§ 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;

* * * * *

(e) * * *

(1) * * *

(i) Except as provided in paragraph (h) of this section for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in subparts B through G and J of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.179(e) and (f), 192.205, 192.227(c), 192.285(e), 192.319(d) through (g), 192.506, 192.634, and 192.636 is not required;

(ii) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines, except the requirements in §§ 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;

* * * * *

■ 5. In § 192.13, paragraph (d) is added to read as follows:

§ 192.13 What general requirements apply to pipelines regulated under this part?

* * * * *

(d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, significant changes that pose a risk to safety or the environment through a management of change process. Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11 (incorporated by reference, *see* § 192.7), that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. A management of change process must include the following: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. For pipeline segments other than those covered in subpart O of this part, this management of change process must be implemented by February 26, 2024. The requirements of this paragraph (d) do not apply to gas gathering pipelines. Operators may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this section, the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

■ 6. In § 192.18, paragraph (c) is revised to read as follows:

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if an operator submits, pursuant to § 192.8, § 192.9, § 192.13, § 192.179, § 192.319, § 192.461, § 192.506, § 192.607, § 192.619, § 192.624, § 192.632, § 192.634, § 192.636, § 192.710, § 192.712, § 192.714, § 192.745, § 192.917, § 192.921, § 192.927, § 192.933, or § 192.937, a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*e.g.,* ''other technology'' or ''alternative equivalent technology'') than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposal or that PHMSA requires additional time and/or more information to conduct its review.

■ 7. In § 192.319, paragraphs (d) through (g) are added to read as follows:

§ 192.319 Installation of pipe in a ditch.

* * * * *

(d) Promptly after a ditch for an onshore steel transmission line is backfilled (if the construction project involves 1,000 feet or more of continuous backfill length along the

pipeline), but not later than 6 months after placing the pipeline in service, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

(e) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (d) of this section.

(f) An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, *see* § 192.7) within 6 months after the pipeline is placed in service, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

(g) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (d) through (f) of this section.

■ 8. In § 192.461, paragraph (a)(4) is revised and paragraphs (f) through (i) are added to read as follows:

§ 192.461 External corrosion control: Protective coating.

(a) * * *

(4) Have sufficient strength to resist damage due to handling (including, but not limited to, transportation, installation, boring, and backfilling) and soil stress; and

* * * * *

(f) Promptly after the backfill of an onshore steel transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), but no later than 6 months after the backfill, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

(g) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (f) of this section.

(h) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. The operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, *see* § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

(i) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (f) through (h) of this section.

■ 9. In § 192.465, the section heading and paragraph (d) are revised and paragraph (f) is added to read as follows:

§ 192.465 External corrosion control: Monitoring and remediation.

* * * * *

(d) Each operator must promptly correct any deficiencies indicated by the inspection and testing required by paragraphs (a) through (c) of this section. For onshore gas transmission pipelines, each operator must develop a remedial action plan and apply for any necessary permits within 6 months of completing the inspection or testing that identified the deficiency. Remedial action must be completed promptly, but no later than the earliest of the following: prior to the next inspection or test interval required by this section; within 1 year, not to exceed 15 months, of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits.

* * * * *

(f) An operator must determine the extent of the area with inadequate cathodic protection for onshore gas transmission pipelines where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in appendix D to this part.

(1) Gas transmission pipeline operators must investigate and mitigate any non-systemic or location-specific causes.

(2) To address systemic causes, an operator must conduct close interval surveys in both directions from the test station with a low cathodic protection reading at a maximum interval of approximately 5 feet or less. An operator must conduct close interval surveys unless it is impractical based upon geographical, technical, or safety reasons. An operator must complete close interval surveys required by this section with the protective current interrupted unless it is impractical to do so for technical or safety reasons. An operator must remediate areas with insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline, in accordance with paragraph (d) of this section. An operator must confirm the restoration of adequate cathodic protection following the implementation of remedial actions undertaken to mitigate systemic causes of external corrosion.

■ 10. In § 192.473, paragraph (c) is added to read as follows:

§ 192.473 External corrosion control: Interference currents.

* * * * *

(c) For onshore gas transmission pipelines, the program required by paragraph (a) of this section must include:

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be conducted when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced, such as through co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up-rating, additional lines, new or enlarged power substations, or new pipelines or other structures;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could cause significant corrosion, impede safe operation, or adversely affect the environment or public;

(3) Development of a remedial action plan to correct any instances where interference current is greater than or equal to 100 amps per meter squared or if it impedes the safe operation of a pipeline, or if it may cause a condition that would adversely impact the environment or the public; and

(4) Application for any necessary permits within 6 months of completing the interference survey that identified

the deficiency. An operator must complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency; or as soon as practicable, but not to exceed 6 months, after obtaining any necessary permits.

■ 11. Section 192.478 is added to read as follows:

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

(a) Each operator of an onshore gas transmission pipeline with corrosive constituents in the gas being transported must develop and implement a monitoring and mitigation program to mitigate the corrosive effects, as necessary. Potentially corrosive constituents include, but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and liquid water, either by itself or in combination. An operator must evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures as necessary.

(b) The monitoring and mitigation program described in paragraph (a) of this section must include:

(1) The use of gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents.

(2) Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling, inhibitor injections, in-line cleaning pigging, separators, or other technology that mitigates potentially corrosive effects.

(3) An evaluation at least once each calendar year, at intervals not to exceed 15 months, to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

(c) An operator must review its monitoring and mitigation program at least once each calendar year, at intervals not to exceed 15 months, and based on the results of its monitoring and mitigation program, implement adjustments, as necessary.

■ 12. In § 192.485, paragraph (c) is revised to read as follows:

§ 192.485 Remedial measures: Transmission lines.

* * * * *

(c) *Calculating remaining strength.* Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness must be determined and documented in accordance with § 192.712.

■ 13. In § 192.613, paragraph (c) is added to read as follows:

§ 192.613 Continuing surveillance.

* * * * *

(c) Following an extreme weather event or natural disaster that has the likelihood of damage to pipeline facilities by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline, such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

(1) An operator must assess the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for the additional assessments required under this paragraph (c)(1).

(2) An operator must commence the inspection required by paragraph (c) of this section within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment required to perform the inspection as determined by paragraph (c)(1) of this section are available. If an operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable.

(3) An operator must take prompt and appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required by paragraph (c) of this section. Such actions might include, but are not limited to:

(i) Reducing the operating pressure or shutting down the pipeline;

(ii) Modifying, repairing, or replacing any damaged pipeline facilities;

(iii) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;

(iv) Performing additional patrols, surveys, tests, or inspections;

(v) Implementing emergency response activities with Federal, State, or local personnel; or

(vi) Notifying affected communities of the steps that can be taken to ensure public safety.

■ 14. In § 192.710, paragraph (f) is revised as follows:

§ 192.710 Transmission lines: Assessments outside of high consequence areas.

* * * * *

(f) *Remediation.* An operator must comply with the requirements in §§ 192.485, 192.711, 192.712, 192.713, and 192.714, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.

* * * * *

■ 15. In § 192.711, paragraph (b)(1) is revised to read as follows:

§ 192.711 Transmission lines: General requirements for repair procedures.

* * * * *

(b) * * *

(1)(i) Non-integrity management repairs for gathering lines and offshore transmission lines: For gathering lines subject to this section in accordance with § 192.9 and for offshore transmission lines, an operator must make permanent repairs as soon as feasible.

(ii) Non-integrity management repairs for onshore transmission lines: Except for gathering lines exempted from this section in accordance with § 192.9 and offshore transmission lines, after May 24, 2023, whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered by an integrity management program under subpart O of this part, it must correct the condition as prescribed in § 192.714.

* * * * *

■ 16. In § 192.712, the section heading and paragraph (b) are revised and paragraphs (c) and (h) are added to read as follows:

§ 192.712 Analysis of predicted failure pressure and critical strain level.

* * * * *

(b) *Corrosion metal loss.* When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, *see* § 192.7); R–STRENG (incorporated by reference, *see* § 192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

(1) If an operator would choose to use a remaining strength calculation method that could provide a less conservative result than the methods listed in

paragraph (b) introductory text, the operator must notify PHMSA in advance in accordance with § 192.18(c).

(2) The notification provided for by paragraph (b)(1) of this section must include a comparison of its predicted failure pressures to R–STRENG or ASME/ANSI B31G, all burst pressure tests used, and any other technical reviews used to qualify the calculation method(s) for varying corrosion profiles.

(c) *Dents and other mechanical damage.* To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows:

(1) Identify and evaluate potential threats to the pipe segment in the vicinity of the anomaly or defect, including ground movement, external loading, fatigue, cracking, and corrosion.

(2) Review high-resolution magnetic flux leakage (HR–MFL) high-resolution deformation, inertial mapping, and crack detection inline inspection data for damage in the dent area and any associated weld region, including available data from previous inline inspections.

(3) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data.

(4) Compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape.

(5) Identify and quantify all previous and present significant loads acting on the dent.

(6) Evaluate the strain level associated with the anomaly or defect and any nearby welds using Finite Element Analysis, or other technology in accordance with this section. Using Finite Element Analysis to quantify the dent strain, and then estimating and evaluating the damage using the Strain Limit Damage (SLD) and Ductile Failure Damage Indicator (DFDI) at the dent, are appropriate evaluation methods.

(7) The analyses performed in accordance with this section must account for material property uncertainties, model inaccuracies, and inline inspection tool sizing tolerances.

(8) Dents with a depth greater than 10 percent of the pipe outside diameter or with geometric strain levels that exceed the lessor of 10 percent or exceed the critical strain for the pipe material properties must be remediated in accordance with § 192.713, § 192.714, or § 192.933, as applicable.

(9) Using operational pressure data, a valid fatigue life prediction model that is appropriate for the pipeline segment, and assuming a reassessment safety factor of 5 or greater for the assessment interval, estimate the fatigue life of the dent by Finite Element Analysis or other analytical technique that is technically appropriate for dent assessment and reassessment intervals in accordance with this section. Multiple dent or other fatigue models must be used for the evaluation as a part of the engineering critical assessment.

(10) If the dent or mechanical damage is suspected to have cracks, then a crack growth rate assessment is required to ensure adequate life for the dent with crack(s) until remediation or the dent with crack(s) must be evaluated and remediated in accordance with the criteria and timing requirements in § 192.713, § 192.714, or § 192.933, as applicable.

(11) An operator using an engineering critical assessment procedure, other technologies, or techniques to comply with paragraph (c) of this section must submit advance notification to PHMSA, with the relevant procedures, in accordance with § 192.18.

* * * * *

(h) *Reassessments.* If an operator uses an engineering critical assessment method in accordance with paragraphs (c) and (d) of this section to determine the maximum reevaluation intervals, the operator must reassess the anomalies as follows:

(1) If the anomaly is in an HCA, the operator must reassess the anomaly within a maximum of 7 years in accordance with § 192.939(a), unless the safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

(2) If the anomaly is outside of an HCA, the operator must perform a reassessment of the anomaly within a maximum of 10 years in accordance with § 192.710(b), unless the anomaly safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

■ 17. Section 192.714 is added to read as follows:

§ 192.714 Transmission lines: Repair criteria for onshore transmission pipelines.

(a) *Applicability.* This section applies to onshore transmission pipelines not subject to the repair criteria in subpart O of this part, and which do not operate under an alternative MAOP in accordance with §§ 192.112, 192.328, and 192.620. Pipeline segments that are located in high consequence areas, as defined in § 192.903, must comply with the applicable actions specified by the integrity management requirements in subpart O. Pipeline segments operating under an alternative MAOP in accordance with §§ 192.112, 192.328, and 192.620 must comply with § 192.620(d)(11).

(b) *General.* Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made to prevent damage to persons, property, and the environment. A pipeline segment's operating pressure must be less than the predicted failure pressure determined in accordance with § 192.712 during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, an operator must obtain the undocumented data through § 192.607.

(c) *Schedule for evaluation and remediation.* An operator must remediate conditions according to a schedule that prioritizes the conditions for evaluation and remediation. Unless paragraph (d) of this section provides a special requirement for remediating certain conditions, an operator must calculate the predicted failure pressure of anomalies or defects and follow the schedule in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. Each condition that meets any of the repair criteria in paragraph (d) of this section in an onshore steel transmission pipeline must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe that will permanently restore the pipeline's MAOP based on the use of § 192.105 and the design factors for the class location in which it is located; or

(2) Repaired by a method, shown by technically proven engineering tests and analyses, that will permanently restore the pipeline's MAOP based upon the determined predicted failure pressure times the design factor for the class location in which it is located.

(d) *Remediation of certain conditions.* For onshore transmission pipelines not located in high consequence areas, an operator must remediate a listed condition according to the following criteria:

(1) *Immediate repair conditions.* An operator must repair the following conditions immediately upon discovery:

(i) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly

shows a predicted failure pressure, determined in accordance with § 192.712(b), of less than or equal to 1.1 times the MAOP.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

(iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0, and the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

(vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

(2) *Two-year conditions.* An operator must repair the following conditions within 2 years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower ⅓ of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iv) For metal loss anomalies, a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with § 192.712(b) at the location of the anomaly, of less than 1.39 times the MAOP for Class 2 locations, or less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, Figure 4, as specified in paragraph (c) of this section.

(v) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, and that has a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(3) *Monitored conditions.* An operator must record and monitor the following conditions during subsequent risk assessments and integrity assessments for any change that may require remediation.

(i) A dent that is located between the 4 o'clock and 8 o'clock positions (bottom ⅓ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis performed in accordance with § 192.712(c) determines that critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and where an engineering analysis of the dent and girth or seam weld, performed in accordance with § 192.712(c), demonstrates critical strain levels are not exceeded. These analyses must consider weld mechanical properties.

(iv) A dent that has metal loss, cracking, or a stress riser, and where an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(e) *Temporary pressure reduction.* (1) Immediately upon discovery and until an operator remediates the condition specified in paragraph (d)(1) of this section, or upon a determination by an

operator that it is unable to respond within the time limits for the conditions specified in paragraph (d)(2) of this section, the operator must reduce the operating pressure of the affected pipeline to any one of the following based on safety considerations for the public and operating personnel:

(i) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;

(ii) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

(iii) A level not exceeding the predicted failure pressure divided by 1.1.

(2) An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. Notification to PHMSA does not alleviate an operator from the evaluation, remediation, or pressure reduction requirements in this section.

(3) When a pressure reduction, in accordance with paragraph (e) of this section, exceeds 365 days, an operator must notify PHMSA in accordance with § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

(4) An operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure and the implementation of the actual reduced operating pressure for a period of 5 years after the pipeline has been repaired.

(f) *Other conditions.* Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules, and methods defined in the operator's operating and maintenance procedures.

(g) *In situ direct examination of crack defects.* Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. ''In situ'' examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

(h) *Determining predicted failure pressures and critical strain levels.* An operator must perform all determinations of predicted failure pressures and critical strain levels required by this section in accordance with § 192.712.

■ 18. In § 192.911, paragraph (k) is revised to read as follows:

§ 192.911 What are the elements of an integrity management program?

* * * * *

(k) A management of change process as required by § 192.13(d).

* * * * *

■ 19. In § 192.917, paragraphs (a) through (d) are revised to read as follows:

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 2, which are grouped under the following four threat categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Stable threats, such as manufacturing, welding, fabrication, or construction defects;

(3) Time independent threats, such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage, to include consideration of seismicity, geology, and soil stability of the area; and

(4) Human error, such as operational or maintenance mishaps, or design and construction mistakes.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4.

Operators must begin to integrate all pertinent data elements specified in this section starting on May 24, 2023, with all available attributes integrated by February 26, 2024. An operator may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this paragraph (b), the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety. An operator must gather and evaluate the set of data listed in paragraph (b)(1) of this section. The evaluation must analyze both the covered segment and similar non-covered segments, and it must:

(1) Integrate pertinent information about pipeline attributes to ensure safe operation and pipeline integrity, including information derived from operations and maintenance activities required under this part, and other relevant information, including, but not limited to:

(i) Pipe diameter, wall thickness, seam type, and joint factor;

(ii) Manufacturer and manufacturing date, including manufacturing data and records;

(iii) Material properties including, but not limited to, grade, specified minimum yield strength (SMYS), and ultimate tensile strength;

(iv) Equipment properties;

(v) Year of installation;

(vi) Bending method;

(vii) Joining method, including process and inspection results;

(viii) Depth of cover;

(ix) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;

(x) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;

(xi) Pipe coating methods (both manufactured and field applied), including the method or process used to apply girth weld coating, inspection reports, and coating repairs;

(xii) Soil, backfill;

(xiii) Construction inspection reports, including but not limited to:

(A) Post backfill coating surveys; and

(B) Coating inspection (''jeeping'' or ''holiday inspection'') reports;

(xiv) Cathodic protection installed, including, but not limited to, type and location;

(xv) Coating type;

(xvi) Gas quality;

(xvii) Flow rate;

(xviii) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);

(xix) Class location;

(xx) Leak and failure history, including any in-service ruptures or leaks from incident reports, abnormal operations, safety-related conditions (both reported and unreported) and failure investigations required by § 192.617, and their identified causes and consequences;

(xxi) Coating condition;

(xxii) Cathodic protection (CP) system performance;

(xxiii) Pipe wall temperature;

(xxiv) Pipe operational and maintenance inspection reports, including, but not limited to:

(A) Data gathered through integrity assessments required under this part, including, but not limited to, in-line inspections, pressure tests, direct assessments, guided wave ultrasonic testing, or other methods;

(B) Close interval survey (CIS) and electrical survey results;

(C) CP rectifier readings;

(D) CP test point survey readings and locations;

(E) Alternating current, direct current, and foreign structure interference surveys;

(F) Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including, but not limited to, direct current voltage gradient or alternating current voltage gradient inspections;

(G) Results of examinations of exposed portions of buried pipelines (*e.g.,* pipe and pipe coating condition, *see* § 192.459), including the results of any non-destructive examinations of the pipe, seam, or girth weld (*i.e.* bell hole inspections);

(H) Stress corrosion cracking excavations and findings;

(I) Selective seam weld corrosion excavations and findings;

(J) Any indication of seam cracking; and

(K) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;

(xxv) External and internal corrosion monitoring;

(xxvi) Operating pressure history and pressure fluctuations, including an analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;

(xxvii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;

(xxviii) Encroachments;

(xxix) Repairs;

(xxx) Vandalism;

(xxxi) External forces;

(xxxii) Audits and reviews;

(xxxiii) Industry experience for incident, leak, and failure history;

(xxxiv) Aerial photography; and

(xxxv) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area.

(2) Use validated information and data as inputs, to the maximum extent practicable. If input is obtained from subject matter experts (SME), an operator must employ adequate control measures to ensure consistency and accuracy of information. Control measures may include training of SMEs or the use of outside technical experts (independent expert reviews) to assess the quality of processes and the judgment of SMEs. An operator must document the names and qualifications of the individuals who approve SME inputs used in the current risk assessment.

(3) Identify and analyze spatial relationships among anomalous information (*e.g.,* corrosion coincident with foreign line crossings or evidence of pipeline damage where overhead imaging shows evidence of encroachment).

(4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and that analyzes the identified threats and potential consequences of an incident for each covered segment. An operator must ensure the validity of the methods used to conduct the risk assessment considering the incident, leak, and failure history of the pipeline segments and other historical information. Such a validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the likelihood of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures needed for each covered segment in accordance with § 192.935 and periodically evaluate the integrity of each covered pipeline segment in accordance with § 192.937. Beginning February 26, 2024, the risk assessment must:

(1) Analyze how a potential failure could affect high consequence areas;

(2) Analyze the likelihood of failure due to each individual threat and each unique combination of threats that interact or simultaneously contribute to risk at a common location;

(3) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and

(4) Evaluate the potential risk reduction associated with candidate risk reduction activities, such as preventive and mitigative measures, and reduced anomaly remediation and assessment intervals.

(5) In conjunction with § 192.917(b), an operator may request an extension of up to 1 year for the requirements of this paragraph by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this paragraph (c)(5), the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S and consider any threats unique to the integrity of plastic pipe, such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.

* * * * *

■ 20. In § 192.923, paragraphs (b)(2) and (3) are revised to read as follows:

§ 192.923 How is direct assessment used and for what threats?

* * * * *

(b) * * *

(2) Section 192.927 and NACE SP0206 (incorporated by reference, *see* § 192.7), if addressing internal corrosion (IC).

(3) Section 192.929 and NACE SP0204 (incorporated by reference, *see* § 192.7), if addressing stress corrosion cracking (SCC).

* * * * *

■ 21. In § 192.927, paragraphs (b) and (c) are revised to read as follows:

§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

* * * * *

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206 (incorporated by reference, *see* § 192.7). The Dry Gas Internal Corrosion Direct Assessment (DG–ICDA) process described in this section applies only for a segment of pipe transporting normally dry natural gas (*see* § 192.3) and not for a segment with electrolytes normally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolytes present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to address internal corrosion effectively and must notify PHMSA in accordance with § 192.18. In the event of a conflict between this section and NACE SP0206, the requirements in this section control.

(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that meets NACE SP0206 (incorporated by reference, *see* § 192.7) and that implements all four steps of the DG–ICDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. The plan must identify the locations of all ICDA regions within covered segments in the transmission system. An ICDA region is a continuous length of pipe (including weld joints), uninterrupted by any significant change in water or flow characteristics, that includes similar physical characteristics or operating history. An ICDA region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located to complete the assessment of the covered segment.

(1) *Preassessment.* An operator must comply with NACE SP0206 (incorporated by reference, *see* § 192.7) in conducting the preassessment step of the ICDA process.

(2) *Indirect inspection.* An operator must comply with NACE SP0206 (incorporated by reference, *see* § 192.7), and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. An operator must explicitly document the results of its feasibility assessment as required by NACE SP0206, section 3.3 (incorporated by reference, *see* § 192.7); if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use actual pipeline-specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of the data used to make those calculations, including, but not limited to, gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossings, river crossings, drains, valves, drips, etc.), topographical data, and depth of cover. An operator must select locations for direct examination and establish the extent of pipe exposure needed (*i.e.,* the size of the bell hole), to account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

(3) *Detailed examination.* An operator must comply with NACE SP0206 (incorporated by reference, *see* § 192.7) in conducting the detailed examination step of the ICDA process. When an operator first uses ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each covered segment associated with the ICDA region and must perform a detailed examination for internal corrosion at each location using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques that can examine for internal corrosion or other threats that are being assessed. One location must be the low point (*e.g.,* sag, drip, valve, manifold, dead-leg) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment, near the end of the ICDA region. Whenever corrosion is found during ICDA at any location, the operator must:

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with § 192.933 if the condition is in a covered segment, or in accordance with §§ 192.485 and 192.714 if the condition is not in a covered segment;

(ii) Expand the detailed examination program to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (*e.g.,* sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined in accordance with paragraph (c)(3) of this section, two additional detailed examinations must be conducted within the covered segment; and

(iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region in which the corrosion was found and remediate identified instances of internal corrosion in accordance with either § 192.933 or §§ 192.485 and 192.714, as appropriate.

(4) *Post-assessment evaluation and monitoring.* An operator must comply with NACE SP0206 (incorporated by reference, *see* § 192.7) in performing the post assessment step of the ICDA process. In addition to NACE SP0206, the evaluation and monitoring process must also include—

(i) An evaluation of the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in § 192.939. An operator must carry out this evaluation within 1 year of conducting an ICDA;

(ii) Validation of the flow modeling calculations by comparison of actual locations of discovered internal corrosion with locations predicted by the model (if the flow model cannot be validated, then ICDA is not feasible for the segment); and

(iii) Continuous monitoring of each ICDA region that contains a covered segment where internal corrosion has been identified by using techniques such as coupons or ultrasonic (UT) sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart and risk factors specific to the ICDA region.

At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7½ months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions, and remediate the conditions the operator finds in accordance with § 192.933 or §§ 192.485 and 192.714, as applicable.

(A) Conduct excavations of, and detailed examinations at, locations downstream from where the electrolytes might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of § 192.478; or

(B) Assess the covered segment using another integrity assessment method allowed by this subpart.

(5) *Other requirements.* The ICDA plan must also include the following:

(i) Criteria an operator will apply in making key decisions (including, but not limited to, ICDA feasibility, definition of ICDA regions and sub-regions, and conditions requiring excavation) in implementing each stage of the ICDA process; and

(ii) Provisions that the analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of § 192.933 may be limited to covered segments.

■ 22. Section 192.929 is revised to read as follows:

§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking?

(a) *Definition.* A Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipeline segment for the presence of stress corrosion cracking (SCC) by systematically gathering and analyzing excavation data from pipe having similar operational characteristics and residing in a similar physical environment.

(b) *General requirements.* An operator using direct assessment as an integrity assessment method for addressing SCC in a covered pipeline segment must develop and follow an SCCDA plan that meets NACE SP0204 (incorporated by reference, *see* § 192.7) and that implements all four steps of the SCCDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. As specified in NACE SP0204, SCCDA is complementary with other inspection methods for SCC, such as in-line inspection or hydrostatic testing with a spike test, and it is not necessarily an alternative or replacement for these methods in all instances. Additionally, the plan must provide for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered pipeline segments to identify whether the conditions for SCC are present and to prioritize the covered pipeline segments for assessment in accordance with NACE SP0204, sections 3 and 4, and Table 1 (incorporated by reference, *see* § 192.7). This process must also include gathering and evaluating data related to SCC at all sites an operator excavates while conducting its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204 (incorporated by reference, *see* § 192.7) indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204, section 5.3 (incorporated by reference, *see* § 192.7), and must include, at a minimum, all data listed in NACE SP0204, Table 2 (incorporated by reference, *see* § 192.7). Further, the following factors must be analyzed as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment, such as soil temperature, moisture, the presence or generation of carbon dioxide, or cathodic protection (CP);

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments;

(iii) The effects of variations in applied CP, such as overprotection, CP loss for extended periods, and high negative potentials;

(iv) The effects of coatings that shield CP when disbonded from the pipe; and

(v) Other factors that affect the mechanistic properties associated with SCC, including, but not limited to, historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.

(2) *Indirect inspection.* In addition to NACE SP0204, the plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using the complementary measurement tools most appropriate for the pipeline segment based on an evaluation of integrated data.

(3) *Direct examination.* In addition to NACE SP0204, the plan's procedures for direct examination must provide for an operator conducting a minimum of three direct examinations for SCC within the covered pipeline segment spaced at the locations determined to be the most likely for SCC to occur.

(4) *Remediation and mitigation.* If SCC is discovered in a covered pipeline segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Removing the pipe with SCC; remediating the pipe with a Type B sleeve; performing hydrostatic testing in accordance with paragraph (b)(4)(ii) of this section; or by grinding out the SCC defect and repairing the pipe. If an operator uses grinding for repair, the operator must also perform the following as a part of the repair procedure: nondestructive testing for any remaining cracks or other defects; a measurement of the remaining wall thickness; and a determination of the remaining strength of the pipe at the repair location that is performed in accordance with § 192.712 and that meets the design requirements of §§ 192.111 and 192.112, as applicable. The pipe and material properties an operator uses in remaining strength calculations must be documented in traceable, verifiable, and complete records. If such records are not available, an operator must base the pipe and material properties used in the remaining strength calculations on properties determined and documented in accordance with § 192.607, if applicable.

(ii) Performing a spike pressure test in accordance with § 192.506 based upon the class location of the pipeline segment. The MAOP must be no greater than the test pressure specified in

§ 192.506(a) divided by: 1.39 for Class 1 locations and Class 2 locations that contain Class 1 pipe that has been uprated in accordance with § 192.611; and 1.50 for all other Class 2 locations and all Class 3 and Class 4 locations. An operator must repair any test failures due to SCC by replacing the pipe segment and re-testing the segment until the pipe passes the test without failures (such as pipe seam or gasket leaks, or a pipe rupture). At a minimum, an operator must repair pipe segments that pass the pressure test but have SCC present by grinding the segment in accordance with paragraph (b)(4)(i) of this section.

(5) *Post assessment.* An operator's procedures for post-assessment, in addition to the procedures listed in NACE SP0204, sections 6.3, ''periodic reassessment,'' and 6.4, ''effectiveness of SCCDA,'' must include the development of a reassessment plan based on the susceptibility of the operator's pipe to SCC as well as the mechanistic behavior of identified cracking. An operator's reassessment intervals must comply with § 192.939. The plan must include the following factors, in addition to any factors the operator determines appropriate:

(i) The evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204, sections 5.3.5.7, 5.4, and 5.5 (incorporated by reference, *see* § 192.7);

(ii) Conditions conducive to the creation of a carbonate-bicarbonate environment;

(iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;

(iv) Operating temperature and pressure conditions, including operating stress levels on the pipe;

(v) Cyclic loading conditions;

(vi) Mechanistic conditions that influence crack initiation and growth rates;

(vii) The effects of interacting crack clusters;

(viii) The presence of sulfides; and

(ix) Disbonded coatings that shield CP from the pipe.

■ 23. In § 192.933, paragraphs (a) introductory text, (a)(1), (b), and (d) are revised and paragraph (e) is added read as follows:

§ 192.933 What actions must be taken to address integrity issues?

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607.

(1) *Temporary pressure reduction.* (i) If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must reduce the operating pressure to one of the following:

(A) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;

(B) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

(C) A level not exceeding the predicted failure pressure divided by 1.1.

(ii) An operator must determine the predicted failure pressure in accordance with § 192.712. An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. The operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure, and the implementation of the actual reduced operating pressure, for a period of 5 years after the pipeline has been remediated.

* * * * *

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period, the operator must notify PHMSA, in accordance with § 192.18, and provide an expected date when adequate information will become available. Notification to PHMSA does not alleviate an operator from the discovery requirements of this paragraph (b).

* * * * *

(d) *Special requirements for scheduling remediation*—(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 (incorporated by reference, *see* § 192.7) in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A metal loss anomaly where a calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with § 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

(iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(C) The crack or crack-like anomaly has a predicted failure pressure,

determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

(vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

(2) *One-year conditions.* Except for conditions listed in paragraphs (d)(1) and (3) of this section, an operator must remediate any of the following within 1 year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower ⅓ of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iv) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 2 locations, and less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, Figure 4, in accordance with paragraph (c) of this section.

(v) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure, determined in accordance with § 192.712(b), of less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(3) *Monitored conditions.* An operator is not required by this section to schedule remediation of the following less severe conditions but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but if an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition:

(i) A dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe), and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and for which engineering analyses, performed in accordance with § 192.712(c), of the dent and girth or seam weld demonstrate that critical strain levels are not exceeded.

(iv) A dent that has metal loss, cracking, or a stress riser, and where engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(e) *In situ direct examination of crack defects.* Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. ''In situ'' examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations

and fracture mechanics models for failure pressure determinations.

■ 24. In § 192.935, paragraphs (a) and (d)(3) are revised to read as follows:

§ 192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* (1) An operator must take additional measures beyond those already required by this part to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Such additional measures must be based on the risk analyses required by § 192.917. Measures that operators must consider in the analysis, if necessary, to prevent or mitigate the consequences of a pipeline failure include, but are not limited to:

(i) Correcting the root causes of past incidents to prevent recurrence;

(ii) Establishing and implementing adequate operations and maintenance processes that could increase safety;

(iii) Establishing and deploying adequate resources for the successful execution of preventive and mitigative measures;

(iv) Installing automatic shut-off valves or remote-control valves;

(v) Installing pressure transmitters on both sides of automatic shut-off valves and remote-control valves that communicate with the pipeline control center;

(vi) Installing computerized monitoring and leak detection systems;

(vii) Replacing pipe segments with pipe of heavier wall thickness or higher strength;

(viii) Conducting additional right-of-way patrols;

(ix) Conducting hydrostatic tests in areas where pipe material has quality issues or lost records;

(x) Testing to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantiate MAOP evaluations, including material property tests from removed pipe that is representative of the in-service pipeline;

(xi) Re-coating damaged, poorly performing, or disbonded coatings;

(xii) Performing additional depth-of-cover surveys at roads, streams, and rivers;

(xiii) Remediating inadequate depth-of-cover;

(xiv) Providing additional training to personnel on response procedures and conducting drills with local emergency responders; and

(xv) Implementing additional inspection and maintenance programs.

(2) Operators must document the risk analysis, the preventive and mitigative measures considered, and the basis for implementing or not implementing any preventive and mitigative measures considered, in accordance with § 192.947(d).

* * * * *

(d) * * *

(3) Perform instrumented leak surveys using leak detector equipment at least twice each calendar year, at intervals not exceeding 7 ½ months. For unprotected pipelines or cathodically protected pipe where electrical surveys are impractical, instrumented leak surveys must be performed at least four times each calendar year, at intervals not exceeding 4 ½ months. Electrical surveys are indirect assessments that include close interval surveys, alternating current voltage gradient surveys, direct current voltage gradient surveys, or their equivalent.

* * * * *

■ 25. In § 192.941, paragraph (b)(1) and the introductory text of paragraph (b)(2) are revised to read as follows:

§ 192.941 What is a low stress reassessment?

* * * * *

(b) * * *

(1) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an indirect assessment on the covered segment at least once every 7 calendar years. The indirect assessment must be conducted using one of the following means: indirect examination method, such as a close interval survey; alternating current voltage gradient survey; direct current voltage gradient survey; or the equivalent of any of these methods. An operator must evaluate the cathodic protection and corrosion threat for the covered segment and include the results of each indirect assessment as part of the overall evaluation. This evaluation must also include, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe where external corrosion assessments are impractical.* If an external corrosion assessment is impractical on the covered segment an operator must—

* * * * *

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Tristan H. Brown,

Deputy Administrator.

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Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation

Final Regulatory Impact Analysis (RIA)

Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments

July 2022Table of Contents

List of Exhibits

Executive Summary

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is finalizing changes to the Federal pipeline safety regulations in Title 49 of the Code of Federal Regulations (CFR) part 192, which covers the transportation of gas by transmission pipelines. This Regulatory Impact Analysis (RIA) documents PHMSA's analysis of the costs and benefits of the final rule entitled *Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments.*

ES-1 Purpose of the Final Rule

The purpose of this final rule is to increase the level of safety associated with the transportation of gas by pipeline. PHMSA is finalizing requirements that address the causes of several incidents, including the 2010 incident on a Pacific Gas and Electric (PG&E) pipeline near San Bruno, CA, by clarifying and enhancing existing requirements.[1] Specifically, this rulemaking addresses safety measures related to integrity management, management of change, corrosion control, extreme weather, and repair criteria. Exhibit ES-1 summarizes key sections of 49 CFR part 192 affected by the final rule. PHMSA is also making various changes to the definitions in part 192 in support of the final rule's provisions. The preamble that accompanies the publication of the final rule in the Federal Register provides more details on the context for the rulemaking, including stakeholder input, and PHMSA's basis and rationale for the requirements.

Exhibit ES-1: Major Final Rule Topic Areas and 49 CFR Section Amendments

Final Rule Topic Area	*Amended Sections of 49 CFR part 192*
Integrity Management	§§ 192.911(k), 192.917(a) through (d), 192.923(b), 192.927(b) & (c), 192.929, 192.935(a) & (d), and 192.941(b)
Management of Change	§§ 192.13, 192.911
Corrosion Control	§§ 192.319(d) through (g), 192.461(a) & (f) through (i), 192.465(d) & (f), 192.473(c), 192.478, and 192.485
Extreme Weather	§ 192.613(c)
Repair Criteria	§§ 192.711(b); 192.712(b) & (c); 192.714; and 192.933(a), (b), (d) & (e)

[1] The Notice of Proposed Rulemaking (NPRM) that preceded this final rule addressed 16 major topic areas. 81 FR 20722 (Apr. 8, 2016). However, PHMSA determined that the most efficient way to manage the proposals in the NPRM was to divide them into three final rulemaking actions. This final rule is the third final rule derived from the NPRM. On October 1, 2019, PHMSA published a final rule to address maximum allowable operating pressure (MAOP) reconfirmation and material properties verification, the expansion of integrity assessments beyond high-consequence areas, the consideration of seismicity, in-line inspection (ILI) launcher and receiver safety, MAOP exceedance reporting, and stronger requirements for assessment methods. 84 FR 52180. A second rulemaking addresses issues related to onshore gas gathering lines.86 FR 63266 (Nov. 15, 2021).

The final rule's requirements and recommendations respond to high-consequence transmission pipeline incidents and changes in the industry since the establishment of existing regulatory requirements. For example, in 2011, the National Transportation Safety Board (NTSB) finalized its report on the 2010 San Bruno pipeline incident. In its report, the NTSB issued several safety recommendations to PHMSA, PG&E, and the California Public Utilities Commission (CPUC). PHMSA specifically considered these NTSB recommendations in developing the NPRM and this final rule.

ES-2 Costs and Benefits

This rule complies with PHMSA's statutory obligations (under 49 U.S.C. 60102) to evaluate the costs and benefits (including environmental and safety benefits) and conduct risk analyses for new rules. In addition to the RIA for this rule, PHMSA has prepared and made available in the docket the Final Regulatory Flexibility Analysis (FRFA) and a Final Environmental Assessment (EA). This RIA fulfills the requirements of Executive Order (EO) 12866[2] and DOT Order 2100.6A ("Rulemaking and Guidance Procedures")[3] to assess the benefits and costs of the rule as well as reasonable alternatives.

The baseline for this regulatory analysis represents PHMSA's best assessment of conditions and standard industry practices absent the final rule. For each topic area, PHMSA describes existing requirements and related assumptions about how current requirements and practices contribute to incremental cost effects due to the rule. The baseline conditions for each topic are described in section 4.

The cost estimates reflect information available to PHMSA at the time of the analysis, including data about the degree to which operators are already complying with final rule requirements and information provided by commenters in response to the proposed rule. The costs and benefits of some final rule provisions cannot be readily quantified or monetized, and PHMSA discusses these effects qualitatively.

The benefits of the final rule will depend on the degree to which compliance actions result in additional safety measures, relative to the baseline, and the effectiveness of these measures in preventing or mitigating future pipeline releases or other incidents. PHMSA changed its benefit analysis approach for the final rule RIA relative to the Preliminary RIA (PRIA), which was posted to the rulemaking docket at the time the NPRM was published. The PRIA quantified and monetized the anticipated benefits of the NPRM pertinent to this final rule. In this RIA, PHMSA does not attempt to quantify or monetize benefits. The decision to not quantify or monetize benefits is based on the public comments received in response to the PRIA and the unresolved uncertainty in quantifying changes in incident rates that can be explicitly attributed to the final rule's provisions.

Exhibit ES-2 presents the final rule's estimated annualized cost, which range from $12.6 to $16.7 million using 3 percent and 7 percent discount rates, respectively. PHMSA estimates costs over a 20-year period, which provides a sufficient duration to account for and capture the important effects of the rule, but not longer than necessary given the additional uncertainty in longer-term estimates. The analysis reports the results in present value terms as of 1/1/2021 and denominator in constant 2019 dollars. Present value and annualized costs are estimated using discount rates of 3 percent and 7 percent.

[2] 58 FR 51735 (Oct. 4, 1993).
[3] https://www.transportation.gov/regulations/dot-order-21006a-rulemaking-and-guidance-procedures.

Exhibit ES-2: Annualized Cost of the Final Rule, Year 1 - Year 20 ($2019 USD thousands)

Provision	***Discount Rate***	
	3%	***7%***
Integrity Management Process Improvements*	$0	$0
Management of Change Process Improvements	$1,194	$1,223
Corrosion Control	$8,662	$8,998
Extreme Weather	$55	$78
Repair Criteria	$2,725	$6,357
Total	**$12,637**	**$16,656**

*No incremental costs are estimated for this topic area.

As part of the regulatory impact analysis for this final rule, PHMSA determined that the final rule:

- Will not have "a significant economic impact on a substantial number of small entities" under the Regulatory Flexibility Act (RFA).[4] The analysis of small entity impacts is in the FRFA in the docket for the rulemaking.
- Does not impose enforceable duties on State, local, or tribal governments or on the private sector of $100 million or more (in 1996 dollars), in any one year and therefore does not have implications under § 202 of the Unfunded Mandates Reform Act (UMRA) of 1995.[5]
- Does not have federalism implications because it does not impose substantial direct compliance costs on State or local governments.
- Will not affect incremental costs (much less than one percent) for distributing natural gas used as fuel, and therefore no Statement of Energy Effects is needed under EO 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.[6]
- Will change the information collection requirements associated with certain natural gas pipelines. As a result, PHMSA is submitting a revised Information Collection Request (ICR) reflecting changes in reporting and recordkeeping requirements to the Office of Management and Budget (OMB).

ES-3 Alternatives Considered

As described in greater depth below, this RIA analyzes the Selected Action Alternative, which is the final rule that will clarify the Integrity Management (IM) requirements and the No Action Alternative.[7] Under the No Action Alternative, the rule would not be finalized.

PHMSA does not expect, compared to the baseline, benefits to public safety, the physical environment, or environmental justice from the No Action Alternative. PHMSA has not selected the No Action Alternative because it would not provide the benefits to public safety and the physical environment (including avoided GHG emissions) expected from the Selected Action Alternative.

[4] 5 U.S.C. 601 et seq.
[5] 2 U.S.C. 1501 et seq.
[6] 66 FR 28355 (May 18, 2001).
[7] The no action alternative is also discussed in detail as part of PHMSA's Final Environmental Assessment, which is included as part of the docket.

ES-4 Uncertainties and Limitations

PHMSA acknowledges uncertainty in its analysis of the costs and benefits related to underlying elements of the analysis, including in particular the unit costs for compliance actions and the overall effectiveness and associated value of avoiding future incidents.

As described for provisions detailed throughout this section, PHMSA's analysis relies in several instances on assumptions about the degree to which operators are already undertaking actions that are consistent with the final rule's requirements (i.e., baseline compliance) as well as the quantity of labor and other drivers of the final rule's costs. Key sources of uncertainty include:

- **Management of Change (MoC) –** There is uncertainty with respect to the proportion of operators that already have compliant MoC processes, and the operator labor required for non-compliant operators to develop and implement MoC processes. Similarly, the analysis assumes a fixed number of events per year.
- **Extreme Weather Events** – There is uncertainty in the assumed number of events, the proportion of operators that will need to make additional updates to their extreme weather event processes, and the quantity of labor required to make those updates for affected operators.
- **Corrosion Control –** There is uncertainty in the assumed proportion of operators that will require incremental compliance action (behavior change) for Close Interval Survey (CIS) and Interference Surveys. There is similar uncertainty in the assumed number of coating surveys performed annually.

PHMSA uses a static inventory of the pipeline infrastructure for its analysis, based on data from 2018. While historical data indicate that pipeline infrastructure change slowly over time, to the extent that there is significant pipeline construction in the future to service new areas and the final rule results in additional requirements for these new lines (e.g., additional reporting), the analysis understates the potential costs and benefits.

There is also substantial uncertainty in the analysis of benefits, with respect both to the effectiveness of compliance actions in mitigating future pipeline incidents, and the safety and environmental value of avoiding such incidents. The benefits of the final rule depend on whether compliance actions result in additional safety measures and on the effectiveness of those measures in preventing or mitigating future pipeline incidents. The primary expected benefits in the final rule arise from a reduction in the number and severity of pipeline incidents and releases averted by implementing the rule's provisions. For the final rule RIA, PHMSA did not quantify or monetize those benefits. The rule's benefits are discussed qualitatively.

The decision to not monetize benefits was based on PHMSA's realization that data limitations prevent the agency from confidently quantifying the benefits. The benefits analysis approach used in the PRIA, but not carried forward into the final RIA, used an uncertain "incidents averted rate" that relied on hazardous liquids pipeline incident data (rather than natural gas incident data) and also relied on assumptions based on "best professional judgment." While professional judgment is a reasonable approach for assessing benefits, public commenters raised legitimate concerns about PHMSA's heavy reliance in the PRIA on best professional judgment and other assumptions in the benefits analysis. For instance, INGAA's comments drilled down on some of the limitations in the PRIA's benefits analysis regarding discovery rates and the potential for failure. INGAA noted that "[t]he PRIA also considered benefits from improving the safety of pipelines to which its proposed regulations do not apply."[8]

[8] PHMSA-2011-0023-0407-A1.

Based on the public comments received and the uncertainty in estimating the extent to which the rule revisions would prevent future incidents on gas pipelines, PHMSA decided that the data limitations highlighted by commenters made it difficult to quantify the rule's benefits with a reasonable level of confidence.

PHMSA also provided historical data on operator-reported incident property damages to help inform understanding of consequences from the sort of pipeline incidents that may be prevented by the rule. However, PHMSA notes that property damages are only one of the consequences of a pipeline incident: the omission of important social costs from incidents reported by operators is an important consideration when evaluating the extent to which historical incident property damages are indicative of potential future avoided damages (i.e., rule benefits). The omitted societal damages associated with pipeline incidents include non-property damages and environmental damages, including potential climate impacts resulting from the uncontrolled release of methane into the atmosphere. Pipeline incidents inflict a range of non-property costs on society, including emergency response, road closures, and litigation. Also omitted from operator-reported property damage estimates are use and non-use values of environmental resources that are affected by an incident. Examples of use value for damaged ecological resources include values placed on recreational activities, such as fishing, boating, swimming, camping, and bird watching. Non-use value is the amount that people are willing to pay to avoid the injury or death to fauna or other ecosystem injuries even if they have no plans to visit the area affected by the incident.

1. Introduction

PHMSA is finalizing changes to the Federal pipeline safety regulations in 49 CFR part 192, which cover the transportation of gas by transmission pipelines. This RIA documents PHMSA's analysis of the costs and benefits of the final rule: *Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments*.

The purpose of the final rule is to increase the level of safety associated with the transportation of gas by pipeline. In this final rule, PHMSA is finalizing requirements that improve safety related to integrity management, management of change, corrosion control, extreme weather, and repair criteria. The changes are intended to address the causes of several incidents, including the 2010 incident on a PG&E pipeline near San Bruno, CA, by clarifying and enhancing existing requirements. The preamble that accompanies the publication of the final rule in the Federal Register provides more details on the context for the rulemaking, including stakeholder input, and the rationale for the final rule's amendments to the Federal pipeline safety regulations.

The final rule completes a subset of proposals in the Notice of Proposed Rulemaking (NPRM),[9] which addressed 16 major topic areas. PHMSA has already completed two additional rulemakings, which were split off from the NPRM. On October 1, 2019, PHMSA published a final rulemaking to address maximum allowable operating pressure (MAOP) reconfirmation and material properties verification, the expansion of integrity assessments beyond high-consequence areas, the consideration of seismicity, in-line inspection launcher and receiver safety, maximum allowable operating pressure exceedance reporting, and strengthened requirements for assessment methods.[10] On November 15, 2021, PHMSA published a second final rulemaking[11] to address issues related to gas gathering lines, which were also proposed in the NPRM.

This analysis fulfills the requirements of Executive Order 12866 to prepare an assessment of the benefits and costs of the final rule as well as reasonable alternatives. It also satisfies PHMSA's statutory obligations to consider the costs and benefits (including safety and environmental benefits) and perform risk analyses for new rules (49 U.S.C. 60102). In addition to the Regulatory Impact Analysis (RIA) for this rule, PHMSA has prepared and made available in the docket the Final Regulatory Flexibility Analysis (FRFA) and a Final Environmental Assessment (EA).

The rest of this section describes the regulatory background and need for the final rule, and we organize the remainder of the RIA as follows:

- Section 2, *Summary of Final Rule Provisions*, provides a description of the provisions included in the final rule;
- Section 3, Regulatory Analysis Framework, provides an overview of the analysis purpose;
- Section 4, *Analysis of Costs and Benefits*, presents PHMSA's estimates cost and benefits;
- Section 5, *Administrative Requirements*, describes administrative requirements for regulatory analyses required for this rule; and,

[9] 81 FR 20722 (Apr. 8, 2016).
[10] Pipeline Safety: Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, 84 FR 52180 (Oct. 1, 2019).
[11] Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, 86 FR 63266 (Nov. 15, 2021).

- Section 6, *References*, lists all sources cited in the text.

1.1 Overview of the Natural Gas Transmission Pipeline Industry

This section describes the natural gas transmission pipeline industry and the entities most likely affected by this rulemaking, including potentially affected small businesses.

There are four broad categories of natural gas pipelines: production, gathering, transmission, and distribution pipelines. Production pipelines are located at the wellhead in preparation for transportation. Gathering lines move gas from the well pad or point of production to another facility for refinement or transmission. Transmission lines generally have a larger diameter, and serve to move gas long distances, often at high pressures. Distribution pipelines move gas to individual homes or businesses for consumption or use. Pipelines may also be intrastate, operating within the geographical boundaries of a single state, or interstate, operating across one or more state lines. Because this final rule applies only to gas transmission lines, this document does not discuss gas production, gathering or distribution infrastructure and their associated issues.

Pipeline operators report data annually to PHMSA that describes the pipeline mileage they operate, including commodity flow statistics and the physical characteristics of pipelines. In 2020, 1,099 operators of gas transmission pipelines and 382 gathering pipeline operators submitted annual reports to PHMSA (PHMSA, 2020). Based on PHMSA 2020 Annual Report mileage data, in 2019, there were 319,223 miles of on- and off- shore natural gas transmission and gathering pipeline mileage in the United States. Of this total, 301,922 miles (94.5 percent) were onshore transmission pipelines (PHMSA, 2020a).[12] PHMSA recently published a Final Rule entitled Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, 86 FR 63266 (Nov. 15, 2021) that expanded the number of miles and operators subject to pipeline safety regulations. However, none of the quantified provisions in this Final Rule will be applicable to these Type C gas gathering lines and therefore the recently published rule will not affect the costs and benefits associated with this Final Rule.

Pipeline operators report mileage for a variety of commodities, including: natural gas, hydrogen gas, landfill gas, propane gas, synthetic gas, and other commodities; however, natural gas pipelines constitute the overwhelming majority (about 99 percent) in terms of mileage service for different commodities.

1.1.1.1 Establishment Size and Economic Performance

NAICS code 486210, Pipeline Transportation of Natural Gas industry, includes many owners and operators of transmission pipelines.[13] According to U.S. Census County Business Pattern data, there were 2,218 establishments operating in this industry during 2016, employing 30,698 people with an annual payroll of $3.8 billion (2019$) (U.S. Census Bureau 2018). The reported number of establishments in 2015 represents approximately a 20 percent decrease compared to 2014 and is the lowest number of establishments since 2011 (U.S. Census Bureau 2018).

[12] Data as-of 6-28-2021.
[13] This industry comprises establishments primarily engaged in the pipeline transportation of natural gas from processing plants to local distribution systems.

1.2 Regulatory Background

PHMSA and its State partners regulate pipeline safety of jurisdictional[14] gas gathering, transmission, and distribution systems under minimum Federal safety standards authorized by statute[15] and codified in the Federal pipeline safety regulations in 49 CFR parts 190 to 199.

PHMSA promulgated the first integrity management (IM) regulations in 2003 for gas transmission pipelines. IM encompasses the activities pipeline operators must undertake to ensure the integrity of their pipelines. The primary goal of the 2003 IM regulations, which became effective in 2004, was to provide a structure to operators for focusing their resources on improving pipeline integrity in the areas where a failure would have the greatest impact on public safety.

IM regulations have not always been effective in identifying and preventing corrosion and other threats to the pipeline. In addition, sweeping changes in the natural gas industry have caused significant shifts in flow direction and supply and demand. The Nation's aging pipeline network faces increased pressures from these changes as well as from the increased exposure caused by a growing and geographically dispersing population.

Improved technology and regulatory requirements applicable to gas transmission pipeline systems have increased the level of safety associated with the transportation of gas. Still, gas transmission pipelines continue to experience failures from causes that IM was intended to address, such as corrosion, and there is a pressing need for improved strategies to protect the safety and integrity of the Nation's pipeline system.

One such incident occurred in San Bruno, California, on September 9, 2010, killing 8 people, injuring 51, destroying 38 homes, and damaging another 70 homes (PG&E incident). In its investigation of the incident, the NTSB found among several causal factors that the operator, PG&E, had an inadequate IM program that failed to detect and repair or remove the defective pipe section.[16] One of the contributing factors to the incident was that PG&E based its IM program on incomplete and inaccurate pipeline information, which led to, among other issues, faulty risk assessments, improper assessment method selections, and internal assessments of the program that were superficial and resulted in no meaningful improvement.

1.2.1. Advanced Notice of Proposed Rulemaking (ANPRM)

Prior to the PG&E incident, PHMSA was developing an advance notice of proposed rulemaking (ANPRM) to request comments regarding whether IM requirements should be changed and whether other issues related to pipeline system integrity should be addressed by strengthening or expanding non-IM requirements. The PG&E incident highlighted the catastrophic danger of inadequate IM and other safety measures on the Nation's gas transmission and gathering pipelines, leading PHMSA to publish the ANPRM on August 25, 2011 (76 FR 53086).

1.2.2. Notice of Proposed Rulemaking (NPRM)

PHMSA took the input it received from that ANPRM and published an NPRM on April 8, 2016, to seek public comments on proposed changes to the gas transmission pipeline safety regulations. PHMSA proposed new pipeline safety requirements and revisions of existing requirements in 16 major topic areas, including those topics addressing Congressional mandates and related NTSB recommendations.

[14] Typically, onshore pipelines involved in the "transportation of gas." See 49 CFR 192.1 and 192.3 for detailed applicability.
[15] 49 U.S.C. 60101 et seq.
[16] NTSB, "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010" (2011).

This final rule addresses topics, including certain IM clarifications, the MoC process, repair criteria improvements, corrosion control, and inspections following natural disasters. Therefore, not all the topics in the NPRM, nor the comments received on those topics, are discussed in this rulemaking.

1.3 ICF: Cost and Benefit Impact Analysis of the PHMSA Natural Gas and Transmission Safety Regulation Proposal (2016)

PHMSA made a number of adjustments in the Final Rule and final Regulatory Impact Assessment ("RIA")[17] in response to the public comments and recommendations from the Gas Pipeline Advisory Committee ("GPAC") to better focus the NPRM's enhanced safety requirements on transmission lines posing the greatest risks to public safety and the environment. For example, as a result of industry comments, a Gulf Interstate Engineering study (2017)[18] provided PHMSA with updated estimates that superseded those used in the PRIA, and the previous approach to calculating and attributing benefits quantitatively was reconsidered and replaced with the qualitative approach presented in the Final Rule.

As part of its consideration of comments, PHMSA reviewed a 2016 report prepared by ICF International[19] on behalf of API. The ICF Study purports to evaluate the costs and benefits in PHMSA's NPRM on the Safety of Gas Transmission and Gathering Pipelines.[20] The ICF Study is of limited value because its cost estimates are predicated on vague methodology and/or unclear assumptions. By way of example, a frequent practice within the ICF Study is that it will copy identical tables throughout the document and provide limited or no explanatory text describing the use of some or all the data within those tables in connection with a particular calculation—leaving it to the reader to divine precisely how ICF arrived at the values in its analysis. Additionally, the ICF Study relies on unsupported assumptions that are inconsistent with observed industry trends and misapprehensions regarding the substantive requirements of the Final Rule.

One area where PHMSA and ICF estimates vary is pipeline mileage impacted by the rule. It is important to note PHMSA estimates that a lower number of pipeline miles will be impacted by the final rule than estimated by ICF. PHMSA's estimates are based on better methodological assessments and more complete information than what is used in the ICF Study.[21] PHMSA also employs fewer and better supported assumptions based upon the current Final Rule than the ICF assumptions identified. Of the ICF Study's sections, 3.1 (Missing Cost for MCA Field Repair of Damages for Transmission Pipeline) and 3.2 (Missing Cost for non-HCA and non-MCA Field Repair of Damages for Transmission Pipeline) were within the scope of this Final rule but contained inaccurate assumptions and unclear methodologies for their estimates. This RIA addresses those sections and specific assumptions further in Section 3.5 on Repair Criteria below.

[17] Doc. No. PHMSA-2011-0023-0488.

[18] This study was conducted after PHMSA published the NPRM, and therefore this information was not reflected in the PRIA. As a result of the study, PHMSA was able to obtain real world numbers to support the final rule. As such, PHMSA is using the average unit cost estimate derived from the study instead of the older estimates used in the PRIA. Gulf Interstate Engineering. 2017. "Pipeline Testing and Inspection Cost Estimates." 1765-000-EBM-0001-00. Oak Ridge National Laboratory

[19] ICF International, "Cost and Benefit Impact Analysis of the PHMSA Natural Gas Gathering and Transmission Safety Regulation Proposal" (July 1, 2016) ("ICF Study") found at https://energyinfrastructure.org/-/media/energyinfrastructure/images/pipeline/related-docs/icf-api-ria-analysissafety-of-gas-transm.pdf.

[20] 81 FR 20722 (Apr. 8, 2016).

[21] PHMSA addresses this issue because it is exemplary of the methodology employed by ICF throughout the report, which relies on assumptions that are not supported with meaningful explanation, but which coincidentally contribute to extremely high compliance estimated costs.

Several sections of the ICF Study address specific provisions of what are now separate regulatory actions. Section 3.3 (Missing Cost for Incidental Mileage for Transmission Pipeline) primarily covers what is now in the Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments Final Rule, while 3.9 (Revised Cost of In-line Inspection) discusses content from the Gas Transmission Final Rule published in 2019, which already required in-line inspections. Section 3.10 (Revised Cost of Pressure Testing) also covered what is in the 2019 rule, with Pressure Testing not mandated but further clarified instead, as is section 3.12 (Revised Benefits of Proposed Material Documentation Requirements for Transmission Pipeline), with 192.607 and the option for non-destructive means also covered in the 2019 Rule. The remaining sections of the ICF Study's gas transmission chapter are not applicable to the current scope or revised content of this Final Rule. Section 3.5 (Revised Cost of Upgrading to ILI for Transmission Pipeline) is not applicable since requirements for upgrading ILI are not included in this Final Rule. Section 3.6 (Revised Cost of Vendors for Transmission Pipeline) is not applicable since PHMSA's cost estimates are based upon the work being done in the most cost-effective manner that an operator would normally conduct operations and maintenance work. PHMSA understands that there are lower costs associated with using company personnel versus using service provider or vendor personnel, and that labor or repair/ upgrade estimates have an amount of general and administrative (G&A) costs embedded in the estimates below.

Finally, section 3.13 (Power Law Recalculation of HCA Cost) is no longer applicable since benefits are no longer quantified in this RIA, based on comments received.

1.4 Need for Action

This section provides a discussion of the need for Federal regulation.

1.4.1. Advance the Goals of the Nation's Pipeline Safety Laws

PHMSA's mission is to protect people and the environment by advancing the safety of pipeline transportation and pipeline facilities. Pipeline accidents can affect surrounding populations, property, and the environment, imposing societal costs in the form of injuries, fatalities, property and environmental damages, business disruptions, and other effects (e.g., evacuations). The final rule advances and supports the achievement of PHMSA's mission by (1) improving public health and safety by reducing transportation-related deaths and injuries, (2) advancing a transportation system to serve the Nation's long-term social, economic, security, and environmental needs, and (3) avoiding methane and other greenhouse gas emissions associated with failures of natural gas transmission pipelines.

Although the Federal Pipeline Safety Regulations (PSR) applicable to gas transmission and gathering pipeline systems, see 49 CFR parts 191 and 192, have increased the level of safety associated with the transportation of gas, serious safety incidents continue to occur on gas transmission and gathering pipeline systems resulting in serious risks to life and property. Indeed, the National Transportation Safety Board (NTSB) concluded in its investigation of the 2010 San Bruno incident that among several causal factors was that PG&E had an inadequate integrity management (IM) program that failed to detect and repair or remove a defective pipe section on its gas transmission line.[22] This final rule addresses several lessons learned following the San Bruno incident and responds to public input received as part of the rulemaking process. The amendments in this final rule clarify certain integrity management provisions, codify a management of change process, update and bolster gas transmission pipeline corrosion control requirements, require operators to inspect pipelines following extreme weather events, strengthen

[22] NTSB, NTSB/PAR-11-01, "Pipeline Accident Report: Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010" (2011) (NTSB Incident Report on San Bruno).

integrity management assessment requirements, adjust the repair criteria for high consequence areas, create new repair criteria for non-high consequence areas, and revise or create specific definitions related to the above amendments.

The rule strengthens protocols for IM, including protocols for repairing anomalous conditions, and improves and streamlines information collection to help drive risk-based identification of the areas with the greatest safety deficiencies. These changes, in conjunction with the expanded assessment requirements from PHMSA's October 2019 final rule titled "Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expanded Assessment Requirements, and Other Related Amendments," facilitate the prompt identification and remediation of potentially hazardous defects and anomalies in pipeline facilities while allowing operators to make risk-based decisions on where to allocate their maintenance and repair resources.

2 Summary of Final Rule Provisions

PHMSA is finalizing the following changes to the Federal pipeline safety regulations set forth in 49 CFR part 192. Exhibit 1 summarizes key sections of 49 CFR part 192 affected by the final rule. Below we summarize the five topic areas covered in the final rule: IM, MoC, corrosion control, extreme weather, and repair criteria.

Exhibit 1: Major Final Rule Topics Areas and 49 CFR Section Amendments

Final Rule Topic Area	*Amended Sections of 49 CFR part 192*
Integrity Management	§§ 192.911(k), 192.917(a) through (d), 192.923(b), 192.927(b) & (c), 192.929, 192.935(a) & (d), and 192.941(b)
Management of Change	§§ 192.13, 192.911
Corrosion Control	§§ 192.319(d) through (g), 192.461(a) & (f) through (i), 192.465 (d) & (f), 192.473(c), 192.478, and 192.485
Extreme Weather	§ 192.613(c)
Repair Criteria	§§ 192.711(b); 192.712(b) & (c); 192.714; and 192.933(a), (b), (d), & (e)

2.1 Integrity Management

PHMSA is adding specificity to the data integration language in the IM regulations to establish several pipeline attributes that must be included in an operator's risk analysis when an operator determines what threats are applicable to a pipeline segment. Further, PHMSA is explicitly requiring that operators integrate into their broader IM program all analyzed information and verify and validate individual data points. Additionally, PHMSA is issuing requirements for applying knowledge gained through an operator's IM program, including provisions for analyzing interacting threats, potential failures, and worst-case incident scenarios from the initial failure to incident termination. Several of these items were proposed in response to findings[23] following the PG&E incident that suggested pipeline operators were often not conducting data analysis, data integration, threat identification, and risk assessment in the manner originally intended and specified in subpart O of part 192.

PHMSA is also strengthening the standards for performing pipeline assessments by incorporating by reference certain consensus standards, particularly as they apply to both stress corrosion cracking and internal corrosion direct assessments. Operators are required to periodically assess the condition of gas transmission pipelines in HCAs and certain non-HCAs in accordance with §§ 192.710, 192.921, and 192.937. When the initial IM regulations were issued in 2003, industry standards did not exist for these types of assessments. By incorporating by reference the standards subsequently published by National Association of Corrosion Engineers (NACE), the American Society of Mechanical Engineers (ASME) and the American National Standards Institute (ANSI), PHMSA is assuring greater consistency, accuracy, and quality when operators perform these assessments.

[23] NTSB, Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010, https://www.ntsb.gov/investigations/accidentreports/reports/par1101.pdf

The final rule clarifies §§ 192.911(k), 192.917(a) through (d), 192.923(b), 192.927(b) and (c), 192.929, 192.935(a) and (d), and 192.941(b) to make improvements to IM program processes:

- Section 192.911(k) is revised to incorporate elements of a MoC process, which is specifically addressed in section 4.2,
- Section 192.917(a) through (d) are revised to clarify how operators identify potential threats to pipeline integrity and use the threat identification in its integrity program. This includes requirements specifically clarifying:
- *Threat Identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see § 192.7),
- *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, § 4. Operators must begin to integrate all pertinent data elements specified in this section starting on the effective date of the final rule, with all available attributes integrated by 18 months after publication of the final rule. An operator must gather and evaluate the set of data specified in paragraph (b)(1) of this section,
- *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, § 5, and analyzes the identified threats and potential consequences of an incident for each covered segment, and
- *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in §§ 4 and 5 of ASME/ANSI B31.8S, and consider any threats unique to the integrity of plastic pipe such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.
- Sections 192.923(b), 192.927(b) & (c), and 192.929 incorporate by reference NACE SP0206 and NACE SP0204 for Internal Corrosion Direct Assessment (ICDA) and Direct Assessment for Stress Corrosion Cracking (SCCDA),
- Section 192.935 (a) and (d) requires that operators identify additional preventive and mitigative (P&M) measures to protect HCAs. HCAs Operators must base the additional measures on specific risk assessments. The existing rule does not prescribe what those additional measures must be, but list examples of measures operators could take. Therefore, the final rule expands the listing of example P&M measures. Examples serve to promote awareness of the range of actions an operator could consider, but do not constitute new or different requirements.
- Section 192.941 (b) clarifies language related to low stress reassessments.

2.2 Management of Change

The final rule revises § 192.911, paragraph (k), to specify the implementation of a MoC process per § 192.13(d), that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary.

Inadequately reviewed or documented design, construction, maintenance, or operational changes can contribute to pipeline safety.

Following the PG&E gas transmission pipeline incident in San Bruno, California, the NTSB investigation determined that a substandard piece of pipe was substituted in the field without proper authorization, design review, or approval. PHMSA determined that the existing MoC requirements and industry practices were not sufficient, and to help reduce future occurrences, determined that specific attributes of the MoC process should be explicitly codified. PHMSA looked to align the regulatory requirements with the requirements outlined in ASME/ANSI B31.8S.

Implementing a MoC process includes operators identifying potential risks associated with potential technical, physical, procedural, or organizational changes, and incorporating planning for each possible situation. Specifically, the final rule requires that:

- Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, significant changes that pose a risk to safety or the environment through a MoC process; and,
- Each operator of an onshore gas transmission pipeline must develop and follow a MoC process, as outlined in ASME/ANSI B31.8S, § 11, that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary.

2.3 Corrosion Control

Based on lessons PHMSA has learned following several pipeline failures and following PHMSA's workshop on pipeline construction in Fort Worth, TX, in 2009,[24] PHMSA determined that construction practices, including the installation of pipe in-ditch, can result in damaged coating that can compromise corrosion control. Further, PHMSA has noted that the existing regulations were not always effective at eliminating cathodic protection deficiencies or at preventing incidents from internal corrosion. PHMSA also determined that additional prescriptive preventative and mitigative measures are needed for managing electrical interference currents and to enhance safety for HCAs.

The final rule includes revised requirements related to internal corrosion, interference surveys, external corrosion monitoring, and external corrosion coating surveys:

- **Interference Surveys** – PHMSA added requirement to § 192.473 (c) which requires interference surveys for a pipeline system to detect the presence and level of any electrical stray current and develop remedial action plans to correct any instances where interference currents are severe.
- **Internal Corrosion** – PHMSA added § 192.478 requiring the development and implementation of monitoring and mitigation programs to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects.
- **External Corrosion Control** – PHMSA revised § 192.465(d) requiring the development of remedial action plans and apply for any necessary permits within six months of completion of the inspection for deficient corrosion monitoring stations.

[24] PHMSA, "New Pipeline Construction Workshop" (Apr. 23, 2009), https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=58.

- **Cathodic Protection –** PHMSA also added § 192.465(f) requiring cathodic protection (CP) surveys to remediate areas with insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline.
- **External Corrosion Control Coating Surveys -** PHMSA added § 192.319(d) through (g) requiring a voltage gradient survey to ensure integrity of the external corrosion coating promptly after a ditch for a steel onshore transmission line is backfilled, but not later than 66 months after placing the pipeline in service.
- **Coatings –** PHMSA also revised § 192.461(a) requiring pipes have coatings sufficient to protect against damage from handling, and § 192.461(f) through (i) requiring voltage gradient tests to ensure no coating damage within 6 months following a pipe repair or replacement.

2.4 Extreme Weather

Extreme weather has been a contributing factor in several pipeline failures. Considering the frequency of these events and their destructive capabilities, it is important that operators adequately protect the public from pipeline risks in the event of a natural disaster or extreme weather. While some operators might voluntarily perform inspections following such events, some operators will not in the absence of a regulatory requirement. PHMSA has found that the 72-hour timeframe is reasonable and achievable in most cases, and it should provide operators the time necessary to safely access the area with personnel and equipment.[25] If an operator finds an adverse condition during the inspection, the operator must take appropriate remedial action to ensure the safe operation of the pipeline.

The final rule requires, under new § 192.613 paragraph (c), that pipeline operators inspect pipelines affected by an extreme weather event or natural disaster that has the likelihood of damage to pipeline facilities by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline itself. This may include events such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline. The final rule includes the following changes:

- Continuing surveillance of pipelines following the events listed above, including for unusual operating and maintenance conditions, and
- Inspection (within 72 hours or as soon as possible once personnel and equipment can safely access the affected area), and such personnel and equipment are available, and remedial action as needed following the events listed above.

2.5 Repair Criteria

The final rule provides clarity and revises repair criteria in § 192.933 for remediating defects discovered in HCA segments. Additionally, §§ 192.711 and 192.714 add requirements for data analysis, assessment methods, and immediate repair conditions, similar to requirements for HCA segments for non-HCA segments. The two-year repair conditions for non-HCA segments are similar as the one-year repair conditions for HCA segments. These changes will ensure the prompt remediation of anomalous conditions that could potentially impact people, property, or the environment commensurate with the severity of the defects, while still allowing operators to allocate their resources to HCAs on a higher-priority basis.

[25] On January 12, 2017, the GPAC voted that the final rule language of § 192.613(c) to provide for pipeline inspections following such events only where technically feasible, reasonable, cost effective, and practicable.

On October 1, 2019, PHMSA published a final rule to make revisions to §§ 191.23, 191.25, 192.619(f), and 192.624(f), which require operators to report MAOP exceedances, develop operation and maintenance procedures to assure MAOP is not exceeded by the amount needed for overpressure protection, and verify MAOP-related records as part of their IM programs. To reconfirm MAOP, PHMSA anticipates that most operators will conduct an Engineering Critical Assessment (ECA) which includes in-line inspections (ILIs) of their pipelines.

During the course of their IM programs, and more specifically when using ILI tools, operators may discover immediate, one-year, or monitored conditions that require repair.

The final rule modifies § 192.933 to clarify and revise repair criteria for HCAs for crack anomalies, certain corrosion metal loss defects, and dents, among other anomaly types discovered during this process. PHMSA is finalizing new criteria to address cracking and crack-like defects because the existing regulations have no repair criteria for these types of critical defects. Additionally, PHMSA is finalizing additional requirements for immediate repair conditions and 1-year conditions for HCA pipeline segments. Such revisions will provide greater assurance that operators will repair injurious anomalies and defects before those defects grow to a size that leak or rupture. In addition, PHMSA is finalizing repair criteria for non-HCAs, whereas before, there were only general requirements in the regulations for operators to perform repairs in non-HCAs. The non-HCA repair criteria is similar to the criteria for HCAs; however, PHMSA has provided longer timeframes for the remediation of conditions that are not categorized as "immediate" to provide operators the ability to prioritize remediating anomalous conditions in HCAs where consequences of a pipeline failure may be greater. Provisions amended include §§ 192.711, 192.712, 192.714, and 192.933.

3 Analysis of Costs and Benefits

PHMSA quantifies and reports costs in monetary terms whenever it is possible to do with sufficient precision to be helpful for decision makers and commenters; however, in some instances it cannot quantify or monetize the costs and therefore presents a qualitative discussion. With respect to benefits, PHMSA elected not to quantify the potential safety improvements and environmental risk reductions achieved by the rule. As discussed in previous sections, the decision to not quantify and monetize benefits was based on the unresolved uncertainty in quantifying changes in incident rates as a result of the rule, which were highlighted in the public comments received in response to the PRIA.

PHMSA estimates costs and benefits over the 20-year period of 2021-2040, which provides a sufficient duration to account for and capture the important effects of the policy, but not longer than necessary given the additional uncertainty in longer-term estimates.

The analysis discounts all costs to a present value of January 1, 2021, using constant 2019 dollars. Present value and annualized costs are estimated using discount rates of 3 percent and 7 percent, consistent with guidance provided by the OMB in Circular A-4.

At the NPRM stage, PHMSA considered two alternatives: the No Action Alternative and the Proposed Action; this RIA discusses the No Action and the Selected Action Alternatives. Under the No Action Alternative, PHMSA would not finalize amendments and changes to revise the Federal PSR. In the Selected Action Alternative, PHMSA revises the Federal PSR to clarify the IM requirements; improve the management of change process; strengthen corrosion control requirements; provide parameters for inspections following extreme events; strengthen requirements related to the IM assessment methods; and improve repair criteria.

Under the no action alternative, PHMSA would not modify or amend the Federal PSR. Pipeline operators would continue to be governed by the requirements of the existing Federal PSR but would not be subject to the new requirements of the final rule.

This section presents PHMSA's analysis of costs and benefits for each major topic area in the final rule RIA, including those for:

3.1 Integrity Management Program Process Clarifications,

3.2 Management of Change Process,

3.3 Corrosion Control,

3.4 Pipeline Inspection Following Extreme Weather Events, and

3.5 Repair Criteria

3.1 Integrity Management Program Process Clarifications

3.1.1. Baseline

The baseline for this analysis involves affected entities already complying with the requirements of 49 CFR part 192, subpart O, which are not altered under the final rule.

3.1.2. Costs

PHMSA's clarifications to IM program process are not expected to impose any new or additional cost burden on pipeline operators as operators are already required to conduct IM. Below we discuss new requirements associated with each topic area and the rationale for assuming that no new costs would apply. In the preliminary regulatory impact assessment (PRIA), committee members representing the

pipeline industry noted the rule has no timeframe for the implementation of data collection and challenged the conclusion that the data collection elements had a cost of zero, as databases may need to be upgraded to implement the listed attributes or because "pigging" of pipelines using in-line inspection tools would be necessary to obtain pertinent data. While PHMSA acknowledges the potential costs associated with data collection, such upgrades have been required by the Code through the IBR of ASME/ANSI B31.8S, § 4. While commenters also stated that PHMSA significantly underestimated the impact and burden caused by codifying and expanding the scope of MoC, these comments did not identify with specificity the problematic areas of PHMSA's approach or provide alternative metrics that PHMSA could use in the economic impact model. In addition, while the PRIA considered repair criteria costs under IM improvements, for the purposes of this analysis, repair criteria was moved to section 3.5 below. Lastly, this final rule does not itself require "pigging" of lines; rather, as explained in section 2.5 above, operators may perform in-line inspection of their lines pursuant to the regulatory amendments introduced in the October 1, 2019, final rule.

Management of Change

Section 192.911(k) requires that an operator's IM program include a MoC process as outlined in ASME/ANSI B31.8S, § 11. PHMSA has determined that more specific attributes of the MoC process should be codified within the text of § 192.911(k). The final rule amends § 192.911(k) to specify that the MoC process must include the reasons for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. These specific IMP-related MoC requirements, listed above, are already required by reference to ASME/ANSI B31.8S (see §192.7(a)). Since these are not new requirements, PHMSA concludes that this revision imposes no additional cost burden on pipeline operators. As described below in section 4.2, the final rule also includes additional MoC requirements for which costs are estimated.

Threat Identification Requirements

Section 192.917 requires data gathering and integration requirements as part of an effective IM program. Data gathering and integration is an important element of good IM practices. Accordingly, the final rule specifies performance-based requirements for collecting, validating, and integrating pipeline data. These requirements add data integration language, list a number of pipeline attributes that must be included in these analyses, explicitly require that operators integrate analyzed information, and ensure data is verified and validated.

The final rule also requires operators to use validated, objective data to the maximum extent practical. If subjective data from SMEs is used, PHMSA requires that operator programs include specific features to ensure the use of consistent and accurate information. These attributes are already required by reference to ASME/ANSI B31.8S, § 4.

Section 192.917 also requires operators to perform risk assessments as part of an effective IM program. The final rule clarifies that operators must perform risk assessments that address worst-case scenarios and that are capable of accounting for uncertainties and quantifying risk-reduction alternatives. The final rule also clarifies that operators use the risk assessment to establish and implement adequate operations and maintenance processes and establish and deploy adequate resources for successful execution of activities, processes, and systems associated with operations, maintenance, preventive measures, mitigative measures, and managing pipeline integrity.

These requirements, including data gathering, integration, risk assessment, and plastic transmission pipeline risk assessment, are already required by reference to ASME/ANSI B31.8S, §§ 4 and 5, as if they were set out in the rule in full (see § 192.7(a)). Therefore, this requirement does not impose an additional cost burden on pipeline operators.

Incorporation by Reference

With regard to conducting integrity assessments using ILI, internal corrosion direct assessment (ICDA), or SCCDA, the final rule invokes certain consensus industry standards by reference. When the IM rule was promulgated in 2003, industry standards for these assessment methods were still under development. Minimal guidance was provided in ASME/ANSI B31.8S, incorporated by reference into regulations, but the current regulations and ASME/ANSI B31.8S are generally silent on specific guidance for successfully performing such assessments. Subsequently, NACE International, and ASME developed consensus industry standards for these assessment methods. These standards have been used since the mid-2000s and are the best available guidance. Most operators already successfully utilize these standards when conducting these types of assessments. Therefore, the incremental cost to operators from incorporating these standards by reference in the pipeline safety regulations would be negligible.

Preventive and Mitigative Measures

Section 192.935 requires that operators identify additional P&M measures to protect HCAs. Operators must base the additional measures on specific risk assessments. Existing regulations do not prescribe what those additional measures must be, however they do list examples of measures operators could take. The final rule will expand the listing of example P&M measures. Examples serve to promote awareness of the range of actions an operator could consider but do not constitute new or different requirements. The final rule also adds specific enhanced measures for managing external and internal corrosion on pipelines inside HCAs. This aspect of the final rule is analyzed in section 4.3, Corrosion Control. Therefore, the proposed changes to the P&M program element requirement will not impose an additional cost burden on pipeline operators.

3.1.3. Benefits

Clarifications to the threat identification processes, baseline assessment methods, preventive and mitigative measures, and periodic evaluations and assessments are beneficial to the continuous improvement of IM. Additionally, these clarifications emphasize the functions that must be accomplished, elaborate on the elements of effective processes, and clearly articulate PHMSA's expectations. The final rule's editorial and language additions from national consensus standards in the areas of validating risk models, conducting integrity assessments, and remediating anomalies will continue to promote public safety and optimal transmission pipeline operation and management, but are not anticipated to result, on their own, in measurable changes in the risk of pipeline releases, incidents or other quantifiable benefits.

3.2 Management of Change Process

3.2.1. Baseline

The MoC requirements in the final rule apply to all onshore gas transmission pipelines; however, similar MoC requirements already exist for pipeline segments in HCAs and control centers, and those operators have formal processes in place to address changes that occur in those areas. PHMSA also recognizes that all pipeline operators currently apply MoC principles with varying degrees of process formality. While PHMSA does not track information related to existing MoC activities, operators who maintain HCA pipelines already apply compliant MoC processes for their HCA pipelines. Thus, PHMSA anticipates that those operators may already apply the same or similar HCA processes to non-HCA pipelines. Alternately, for operators of non-HCA pipelines only, PHMSA assumes that some portion of them will now require MoC procedures.

API commented through Section 3.11 of the ICF Study (Revised Cost for Management of Change for Transmission Pipeline) claiming that management of change (MOC) would affect all operators, but operators of HCA pipeline mileage are already required to adopt MOC procedures and compliance activities under their IM programs. In this RIA, PHMSA has estimated costs for operators that do not

have MOC procedures. Since operators with HCA mileage already have MOC procedures, PHMSA estimates that 20 percent of non-HCA-only operators do not have MOC procedures and thus only 114 operators will be required to respond to MOC events until this rule. Also, PHMSA estimates that four MoC events per year will be required for these operators, based on subject matter expertise, and that most operators are already implementing MOC procedures on their pipeline systems.

3.2.2. Costs

The final rule's MoC requirements result in two sources of cost for pipeline operators:

- A one-time cost to develop their MoC program, and
- Annually recurring costs to respond to previously unaddressed MoC events.

As described below, PHMSA used professional judgment to estimate the quantity and type of labor required to develop and implement MoC processes for both the one-time and annual cost components. Given the uncertainty in the labor estimates, PHMSA used a range of values to capture instances where some formal processes already exist (low cost) and cases where no formal MoC processes exist (high cost). PHMSA carries forward the average of these two cost values for estimating the total cost of the provision for affected operators.

PHMSA made the following assumptions with respect to the set of operators incurring costs to comply with this provision:

- **Operators of HCA pipelines have no incremental costs.** Operators who maintain HCA pipelines already apply compliant MoC processes for their HCA and non-HCA pipelines, or would incur minimal costs in extending those processes to their non-HCA pipelines to the extent these segments aren't currently covered by operators.
- **Other operators, who maintain only non-HCA pipelines, may already follow adequate MoC procedures.** PHMSA assumes that 20 percent of non-HCA-only operators need to develop and formalize MoC processes to comply with the final rule.[26] Some of these operators may need to review and update existing procedures, while others may need to establish new processes. There are currently 569 operators who maintain only non-HCA miles, and therefore PHMSA assumes 114 operators (20 percent) will incur one-time and annual incremental compliance costs.[27]

In the one-time and annual cost estimates that follow, PHMSA uses industry- and occupation-specific labor rates to quantify operators' labor costs based on hourly wages data from the Bureau of Labor Statistics (BLS) for the Pipeline Transportation of Natural Gas industry (NAICS 486200), as shown below in Exhibit 2.[28] We include labor costs for four occupations in the pipeline transportation industry (NAICS 486200): Mechanical Engineer, Manager, Project Engineer, and Unit Operator.

[26] This assumption is consistent with PHMSA's assumption in the PRIA for the proposed rule.
[27] PHMSA, "2018 Annual Report "at part L (2020).
[28] In the PRIA for the proposed rule, wage data for the "oil and gas extraction industry" (NAICS code: 211111) was used to estimate labor costs. For the final rule, it was determined these were not an accurate representation of industry wages impacted by this regulation. Instead, PHMSA used data for the "pipeline transportation of natural gas industry" (NAICS code: 486200), which are lower than the wages used in the PRIA, because that data more accurately captures labor costs for the pipeline industry.

Exhibit 2: Labor Rates for the MoC Cost Estimates ($2019)

Occupation Code	*Occupation*	*Labor Category*	*Mean Hourly Wage ($/hr.)*[1]	*Total Labor Cost ($/hr.)*[2]
17-2141	Mechanical Engineer	Senior Engineer	$46.34	$67.55
11-0371	Transportation, Storage, and Distribution Managers	Manager	$52.58	$76.65
17-2111	Health and Safety Engineers except Mining Safety Engineers and Inspectors	Project Engineer	$51.00	$74.34
47-5013	Service Unit Operators, Oil, Gas & Mining	Operator	$25.79	$37.59

Notes:
[1] Mean hourly wages are reported directly from the Bureau of Labor Statistics Occupational Employment Statistics for the Pipeline Transportation of Natural Gas Industry (U.S. BLS, 2020).
[2] Mean hourly wage adjusted to account for mean benefits, using the Employer Cost of Employee Compensation report estimate that wages composed 68.6 percent of total labor cost as of December 2019 (U.S. BLS, 2020).

One-Time Costs

Exhibit 3 presents one-time unit costs for the development of formal MoC processes. This includes a set of four key operator activities and an associated level of effort for each end of the range. Activities include reviewing existing MoC procedures for IM program- and Control Center-related changes, revising and expanding the scope of procedures, establishing new procedures, and providing personnel with implementation guidance and instructions. For each operator, PHMSA estimates a total labor requirement of 23 to 100 hours. The lower bound represents instances where operators may have informal procedures in place, and they only need to formalize or update existing procedures. The higher bound represents instances where operators must develop a new set of MoC processes. Based on the labor requirements for senior engineers described above and hourly wage rates, PHMSA estimates one-time, per-operator costs for MoC processes of $1,554 to $6,755 or an average of $4,024 per operator (Exhibit 3).

Exhibit 3: One-Time Costs for MoC Process Development by Operator ($2019)

Activity	*Low Estimate*		*High Estimate*	
	Hours	*Cost*	*Hours*	*Cost*
Review Existing MoC procedures for IMP- and Control Center- related changes	3	$203	0	$0
Revise and expand scope of procedures	16	$1,081	0	$0
Establish procedures	0	$0	80	$5,404
Notify personnel and provide implementation guidance and instruction	4	$270	20	$1,351
Total	**23**	**$1,554**	**100**	**$6,755**
Average One-Time Cost Per Operator	**$4,154**			

Notes:
1. Hours estimated based on PHMSA best professional judgement.
2. Costs estimated by multiplying the hours by the Mechanical Engineer (Senior Engineer) in the Gas Pipeline industry wage rate from Exhibit 2 (U.S. BLS, 2019).

Annual Costs

Consistent with the assumptions in the PRIA, PHMSA assumes that operators engaging in incremental compliance activities (i.e. 20 percent of non-HCA-only operators) respond to four MoC events per year. PHMSA estimates the quantity of labor required to respond to each event based on an assumed mix of labor categories in the gas pipeline transportation industry. Exhibit 4 presents the resulting per-event estimate, using mean hourly wages estimated by PHMSA and reported in Exhibit 2. The estimated response cost attributed to this provision is $2,648 per MoC event, or approximately $10,592 per operator per year assuming four responses.

Exhibit 4: Per-Event Cost for Implementing MoC Processes

Activity	*Labor Category*	*Labor Cost ($/hr.)* [1]	*Hours*[2]	*Cost per Activity*
Maintenance/operating personnel or engineer identifies a change invoking process	Operator	$37.59	1	$38
Obtain approval to pursue change	Manager	$76.65	1	$77
Evaluate and document technical and operational implications of the change	Mech. Engineer	$67.55	12	$811
Obtain required work authorization (e.g. hot work and lockout-tag out permits	Project Engineer	$74.34	3	$223
Formally institutionalize change in official "as-built" drawings facilities lists, data books, and procedure manuals	Project Engineer	$74.34	8	$595
Communicate change to all potentially affected parties	Manager	$76.65	2	$153
Train and qualify involved personnel	Operator	$37.59	20	$752
	TOTAL		**47**	**$2,648**

Notes:
[1] Labor rates as reported in Exhibit 2 above.
[2] Hours estimated based on PHMSA best professional judgment.

Total Cost

Exhibit 5 presents the combined one-time and annual costs for 114 operators to update and maintain formal MoC procedures. This includes $474,000 in one-time costs, and $1.2 million per year annually thereafter for responding to events. Undiscounted total costs of complete compliance over the entire analysis period are estimated to be $23 million dollars.

Exhibit 5: Total Undiscounted MoC Process Improvement Cost ($2019)

	One-Time Cost (2021) [1]	*Annual Costs (2021- 2040)* [2]
Baseline	$0	$0
Final Rule	$473,600	$1,207,410
Undiscounted Total Cost Across All Years (2021-2040)	$473,600	$22,940,782

Notes:
1 One-time costs are based on Exhibit 3 multiplied by the number of operators (114).
2 Annual costs are based on Exhibit 4 ($2,648) multiplied by the number of operators (114) and events (4).

Exhibit 6 shows the net present value and annualized costs, based on 3 percent and 7 percent discount rates. The present value of costs is approximately $13 to $18 million, or an annualized value of $1.19 to $1.22 million per year.

Exhibit 6: MoC Provision Net Present Value (NPV) and Annualized Cost, Year 1 - Year 20 ($2019)

Discount Rate	*3% Discount Rate*	*7% Discount Rate*
Net Present Value	$17,768,292	$12,952,897
Annualized	$1,194,308	$1,222,662

Notes:
1. NPV of costs from 2021-2040 reported as of January 1, 2021. Annualized value reported over 2021-2040.
2. For purposes of estimating NPV and annualized costs, costs are assumed to occur at the beginning of each period.

3.2.3. Benefits

Efficient and effective MoC programs are important for IM, streamlining repairs, and reducing accidents. MoC affects all aspects of pipeline design, construction, operation, and maintenance. PHMSA does not track specific incidents caused by improper procedures, or otherwise estimate risk reductions associated with specific change-based management processes. However, relatively recent, high-consequence incidents have occurred where inadequate change control, including field change control, contributed to the incident. These include liquid pipeline incidents in Walnut Creek, CA and the PG&E gas pipeline incident in San Bruno, CA (National Transportation Safety Board 2011, 2002; California Office of the State Fire Marshall 2005).[29] For example, an unqualified short piece of pipe (commonly referred to as a pup piece) contributed to the PG&E incident. This pipe piece was apparently inserted during a field change and was not properly approved or documented (National Transportation Safety Board 2011). An effective MoC process may prevent such erroneous substitutions of substandard material during pipeline construction.

Specifically, § 192.13(d) may reduce the risk of inadequate quality assurance and quality control procedures that cause a pipeline failure resulting in a release or an incident or increase the magnitude of such a release or incident. For example, these provisions could prevent cases like the PG&E incident, where the installation of a substandard and poorly welded pipe section with a visible seam weld flaw grew over time and caused the pipeline to rupture. Additionally, these requirements reduce risks

[29] California Office of the State Fire Marshall, "Notice of Violation And Civil Penalty Walnut Creek Pipeline Explosion and Fire (11-09-04)" (2005); NTSB, NTSB/ PAR-11/01, "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010." (2011).

associated with an inadequate pipeline IM program, which may fail to detect and repair or remove the defective pipe section.

There has been a total of 1,136 incidents, 22 deaths, 47 injuries, and $766 million in damages associated with all incidents reported to PHMSA from 2010 to 2021 that occurred in non-HCA locations.

PHMSA has no data with which to quantify with confidence how release or incident rates will change as a result of this provision. Exhibit 7 summarizes the 1,136 incidents cited above, along with average per-incident damages, including average property damages, deaths, and injuries per incident.

These incidents resulted in an average of approximately $0.95 million in total damages per incident. In addition to unquantified environmental damages, PHMSA estimates total per-incident damages as the sum of property damages, deaths, and injuries, where the number of deaths and injuries are monetized based on DOT guidance, presented in Exhibit 8.

Exhibit 7: Incidents in non-HCA locations, 2010 - 2021

Year	*Number*	*Total Property Damages ($2021)*	*Deaths (# of persons)*	*Injuries (# of persons)*
2010	78	$24,502,652	2	10
2011	95	$117,155,670	0	1
2012	76	$50,714,052	0	7
2013	84	$47,617,787	0	2
2014	106	$48,007,014	1	0
2015	121	$50,820,783	5	3
2016	79	$112,189,914	3	3
2017	91	$41,381,179	3	2
2018	102	$67,869,308	1	5
2019	112	$102,581,486	1	8
2020	108	$51,529,029	2	2
2021	84	$51,766,176	4	4
Total	**1,136**	**$766,135,051**	**22**	**47**
Average	**94.67**	**$63,844,588**	**1.83**	**3.92**
Total Damages Per Incident	**$954,197**			

Notes: PHMSA Incident Data filtering for onshore incidents, in non-HCA locations. Total incident damages include value of lost gas, public and private property damage, emergency response costs, and value of life ($11.8 million) and serious injury ($1,239,000) on a per incident average basis.

Exhibit 8: Unit Values for Avoided Human Health Impacts

Assumption	*Value*	*Unit*
Value per Saved Life	$11,800,000	$2021 per person
Value per Serious Injury	$1,239,000	$2021 per person

Source: U.S. DOT 2022. Value per serious injury is calculated as a fraction of VSL (10.5% of $11.8 million).

3.3 Corrosion Control

3.3.1. Baseline

Corrosion continues to be a significant problem for gas transmission pipelines and a common cause of pipeline incidents. PHMSA's incident data indicates that since 2010 there have been 111 pipeline incidents primarily attributed to pipeline corrosion, with approximately an even split between internal and external corrosion. These incidents caused $25.5 million in damages. Below we summarize the baseline for the final rule provisions related to corrosion control.

Internal Corrosion

Internal corrosion incidents, based on PHMSA's incident data, include four subcategories for the primary cause – corrosive commodity, water or acid, microbial, and other – which are all required to be monitored per new § 192.478. Section 192.477 currently prescribes requirements to monitor internal corrosion if corrosive gas is being transported. However, the existing rules do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system modifications, gas supply changes, upset conditions, or other changes. However, monitoring these contaminants to ensure the quality of delivered product is already part of some pro forma tariffs regulated by FERC. For example, the pro forma tariff of El Paso Natural Gas Company generally requires a shipper on its mainline system to warrant that the gas at the receipt point is free of water and hydrocarbons in liquid form, the gas does not contain more than five grains of total sulfur per one hundred standard cubic feet, and it takes every reasonable effort to keep the gas delivered free of oxygen (El Paso Natural Gas Company, L.L.C., EPNG Tariffs 2012). Additionally, El Paso's tariff obliges El Paso to ensure the gas quality of natural gas transported on its system at the delivery point (e.g., for water contamination, hydrogen sulfide, carbon dioxide, temperature, dust, gums, solid matter, and other diluents). Pipeline operators are assumed therefore to already have the infrastructure in place to comply with § 192.478. The addition to § 192.478 is not expected to add any incremental compliance activities or costs, but rather codifies existing practice into regulation.

Interference Current Surveys

In 2003, PHMSA issued Advisory Bulletin ADB-03-06.[30] The bulletin advised operators of natural gas transmission pipelines to determine whether new steel pipelines are susceptible to detrimental effects from stray electrical currents, and, if so, to carefully monitor and mitigate such detrimental effects. Since this Advisory Bulletin, PHMSA has identified several cases where significant pipeline defects are attributed to corrosion caused by interference currents. PHMSA believes additional requirements are necessary that explicitly oblige operators to conduct interference surveys and remediate adverse conditions in a timely manner. Under the new requirements, operators are required to include interference surveys to detect the presence of interference currents and to take remedial actions within 6 months of completing the survey. Interference currents can negate the effectiveness of cathodic protection systems. Operators are required to some degree by 49 CFR part 192, subparts I to monitor and mitigate detrimental interference currents.

External Corrosion Monitoring

External corrosion continues to be a primary incident cause for gas transmission pipelines. External corrosion incidents, based on PHMSA's incident data, include six subcategories for the primary cause: galvanic, atmosphere, stray current, microbial, selective seam, and other.

Existing regulations in § 192.465 require operators to monitor external corrosion with cathodic protection but do not specify the timeframe in which remedial actions are required to correct deficiencies, only that remedial actions must be promptly taken. To address this gap, the final rule amends § 192.465 to require

[30] 68 FR 64189 (Nov. 12, 2003).

operators of transmission lines to conduct close-interval surveys (CIS) if annual test station readings indicate cathodic protection is below the level of protection required in 49 CFR part 192, subpart I. The final rule further defines "prompt remediation" to restore adequate corrosion control as meaning within one year of identifying the deficiency. The final rule requires explicit standards for timeliness of corrective action, the costs for which are estimated below.

External Corrosion Surveys

The final rule adds a paragraph to § 192.319(d), which includes two parts. First, all newly installed transmission pipelines undergo a physical coating assessment using either alternating current voltage gradient (ACVG) or direct current voltage gradient (DCVG) to locate coating flaws. Second, moderate or severe coating damages must be remediated by recoating. The rationale behind this change is that most operators perform the required high voltage holiday detection (called "jeeping") on the pipeline prior to it being set into the ditch, however, coating damage can occur after the pipe is lowered into the ditch and backfilled. Many of the high resistance coatings are brittle. Impacts with a rock, debris, or the ditch wall can damage external coatings. Over time, if the cathodic protection electrical potential is not sufficient, or if there are interference currents, external corrosion can occur as a result of this damage during installation.

Besides damage to fusion bonded epoxy coatings, field wrapped joints are also prone to construction damage. Testing the newly installed pipeline after backfilling is an excellent way of finding potential flaws in the coating that occur during installation of the pipe in the ditch and that could, over time, enable external corrosion to affect pipeline integrity. The final rule requires that operators perform a coating survey after initial backfill to identify coating damage that might have occurred during the backfill process. However, since this is for new pipelines only, it does not apply to existing pipelines. Therefore, there is no current cost impact on existing pipelines or pipeline operators.

Section 192.461 currently prescribes requirements for external protective coating systems, however, certain types of coating systems used extensively in the pipeline industry can shield the pipe from cathodic protection if the coating dis-bonds from the pipe. The NTSB determined this was a significant contributing factor in the major crude oil spill that occurred on an Enbridge pipeline near Marshall, Michigan, in 2010 (National Transportation Safety Board 2012). PHMSA determined additional requirements are necessary to specify that coating should be non-shielding to cathodic protection and to verify that pipeline coating systems for protection against external corrosion have not become compromised and have not been damaged during the installation and backfill process.

Currently, § 192.461(a)(4) prescribes that coatings have sufficient strength to resist damage due to handling and soil stress. The final rule revises this section to clarify and expand on the types of activities covered by the general term "handling." It will specify that coatings selected have sufficient strength to adequately withstand handling throughout the entire installation process after being applied to the pipe (transportation, field handling, installation, boring, backfilling, and soil stresses). For example, this requirement provides greater assurance that operators specify the correct coating for the intended application (e.g., avoid pipe coatings designed for direct burial when the pipe is installed by boring methods). This requirement comports with current industry standards that have evolved in recent years to address this aspect of pipeline construction

A new paragraph, § 192.461(f), requires a coating survey using either ACVG or DCVG whenever a repair is made that results in more than 1000 feet of backfill or if other assessment methods show the possibility of coating issues in the area of the repair. If an operator finds either moderate or severe coating damage via the survey, then prompt remedial action would be required to mitigate the situation. Currently, post-backfill coating surveys are not normally completed in many locations in areas that are subject to future external corrosion due to coating flaws.

3.3.2. Costs

Internal Corrosion

As described above, PHMSA acknowledges that while there may be compliance costs, precisely how much those compliance costs are is hard to determine because of uncertainties regarding operators' compliance strategies with respect to existing regulations.

Interference Surveys

Interference surveys detect the presence and level of any electrical stray current. Interference surveys must be conducted when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced, such as through co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up-rating, additional lines, new or enlarged power substations, or new pipelines or other structures.

Interference surveys are used to determine the cause of the interference and whether the level could cause significant corrosion, impede safe operation, or adversely affect the environment or public to locate, analyze, and evaluate the coating condition of buried pipelines.

External Coating Surveys After Pipe Repair or Replacement. DCVG or ACVG surveys are used to ensure the external pipe coating has not been damaged when the pipe has been excavated for a repair or replacement and are conducted after soil cover has been reinstalled.

In a DCVG survey, a direct current signal is applied to the pipeline and the voltage gradient in the soil above the measured pipeline. ACVG surveys uses an alternating current signal applied to the pipeline to create the voltage gradient at the location of a coating defect.

The cost of DCVG and ACVG surveys include the costs associated with crew, equipment, vehicles, and survey analysis, but does not include any verification digs. PHMSA assumes each survey runs for 12 hours and that the pipeline is located in a place that is walkable and accessible.

PHMSA uses an average unit cost of $1.10 dollars per foot for DCVG or ACVG surveys to estimate the cost of this provision (Gulf Interstate Engineering, 2017).[31] The study provided PHMSA with updated estimates that superseded those used in the PRIA, generating a slight reduction in compliance miles (from 2,711 to 2,381) and an increase in unit costs (from $0.91 to $1.10 per foot). In addition, based on professional judgement of subject matter experts, PHMSA assumes 20 percent of gas transmission pipelines, by mileage, are already in compliance due to existing CFR corrosion requirements listed in 49 CFR part 192, subpart I.

Exhibit 9: Interference Survey Costs (seven-year costs) ($2019)

Total Miles	*Current Non-Compliance*	*Non-Compliance, Miles*	*Incremental Compliance Requirement*	*Incremental Compliance, Miles*	*Cost per Foot*	*Total Cost (over 7 year period)*
297,648	80%	238,119	1%	2,381	$1.10	$13,828,848

Notes: The total miles data is from (PHMSA, 2020). PHMSA estimates about 20 percent of miles would already be in compliance due to industry best practices or other requirements in the CFR.

For the remaining pipelines, PHMSA assumes that 1 percent will have an incremental need for the surveys once every seven years. PHMSA assumes $1/7^{th}$ of the miles would be inspected each year (i.e. 2,381 / 7 = 340 miles are inspected per year; see Exhibit 9). The total cost for all 2,381 affected miles to

[31] This study was conducted after PHMSA published the NPRM, and therefore this information was not reflected in the PRIA. As a result of the study, PHMSA was able to obtain real world numbers to support the final rule. As such, PHMSA is using the average unit cost estimate derived from the study instead of the older estimates used in the PRIA.

complete their surveys (over a seven-year period) is estimated to be $13.83 million . Annualized over the 20-year analysis period, the cost of this provision is $1.97 million per year (Exhibit 9).

External Corrosion Monitoring

Close Interval Surveys (CIS) – also known as potential gradient surveys – are one of several methods for assessing the effectiveness of cathodic protection (CP) systems used on buried pipelines. CIS are often used in External Corrosion Direct Assessment (ECDA) pipeline inspections.

These unit CIS costs are independent of pipe diameter but are dependent on segment length. They include cost of survey crew, equipment, vehicles, and survey analysis but do not include any verification digs. Each test is run for 12 hours and assumed to be for a pipeline that is walkable and accessible.

To estimate the costs associated with CIS for external corrosion monitoring, PHMSA uses an average unit cost of $0.89 dollars per foot for CIS (Gulf Interstate Engineering, 2017).[32] In addition, PHMSA assumes 10 percent of pipelines, by mileage, are already in compliance. For the remaining pipelines, PHMSA assumes that 0.5 percent[33] will have an incremental need for CIS based on the rate of test station readings out of specification. The total cost for this provision is estimated to be $6.3 million per year for the duration of the analysis period (Exhibit 10).

Exhibit 10: Annual Close-Interval Survey Costs ($2019)

Total Miles	*Current Non-Compliance*	*Non-Compliance, Miles*	*Incremental Compliance Requirement*	*Incremental Compliance, Miles*	*Cost per Foot*	*Total Annual Cost*
297,648	90%	267,883	0.5%	1,339	$0.90	$6,303,524

Notes: PHMSA relies on unrounded estimates of the cost per foot based on (PHMSA, 2020). Estimates do not generate exact annual cost due to rounding.

External Corrosion Surveys

The costs for external corrosion coating surveys are based on the same DCVG/ACVG cost used for interference surveys above: $1.10 per foot (Gulf Interstate Engineering 2017). In addition, PHMSA assumes operators perform 240 surveys per year, with an average study length of 500 feet. The total cost for this provision is estimated to be $134,046 per year for the duration of the analysis period.

Total Costs

Total undiscounted costs for corrosion control are summarized in Exhibit 11, at $8.4 million per year.

Exhibit 11: Total Annual Corrosion Control Costs ($2019)

Corrosion Control Subcomponent	*Annual Cost*
Interference Surveys	$1,971,915
External Corrosion Monitoring	$6,303,524
External Corrosion Surveys	$134,046
Total Annual Cost	**$8,409,485**

Notes: Assumes that interference surveys occur every 7 years.

[32] This is the average cost per foot across a range of values for segments of different length presented in Gulf Interstate Engineering (2017). Values ranged from $1.79 per foot for segments of 2,500 feet or less, down to $0.37 per foot for segments more than 30,000 feet.
[33] Reflects long-standing requirements for operators to have CP systems and check test stations annually, and PHMSA inspection experience.

Exhibit 12: Corrosion Control Costs Net Present Value, Year 1 – Year 20 ($2019)

Discount Rate	*3% Discount Rate*	*7% Discount Rate*
Net Present Value	$128,865,261	$95,326,520

Notes:
1. NPV of costs from 2021-2040 reported as of January 1, 2021. Annualized value reported over 2021-2040.
2. For purposes of estimating NPV, costs are assumed to occur at the beginning of each period.

3.3.3. Benefits

The number of releases and incidents attributed to corrosion continue to occur at a high rate. Furthermore, PHMSA believes current requirements are not sufficient at preventing releases and incidents caused by damage from construction practices that may compromise pipe and are not always effective at eliminating cathodic protection deficiencies, detecting interference currents, and preventing incidents from corrosion.

From 2010 to 2021 there have been a total of 149 incidents, including over $197 million in damages associated with incidents where internal and external corrosion was identified as the primary cause across all locations. This is apart from unquantified environmental impact associated with releases and incidents. Exhibit 13 summarizes these incidents, along with average per-incident damages.

These incidents resulted in an average of over $1.3 million in total damages per incident. PHMSA estimates total damages per incident as the sum of property damages, deaths, and injuries, where the number of deaths and injuries are monetized based on DOT guidance, presented in Exhibit 8.

Exhibit 13: Incidents Caused by Corrosion, 2010 - 2021

Year	*Number*	*Total Property Damages ($2021)*	*Deaths (# of persons)*	*Injuries (# of persons)*
2010	*14*	*$7,650,342*	*0*	*0*
2011	13	$48,790,333	0	0
2012	13	$8,815,869	0	0
2013	12	$10,739,052	0	2
2014	13	$4,010,698	0	0
2015	16	$3,139,363	0	0
2016	10	$79,772,688	0	1
2017	12	$7,757,993	0	0
2018	7	$5,329,862	0	0
2019	11	$4,784,498	0	0
2020	21	$13,602,949	0	0
2021	7	$2,023,065	0	0
Total	**149**	**$196,679,382**	**0**	**3**
Average	**12.42**	**$16,389,949**	**0.00**	**0.25**
Total Damages Per Incident	**$1,344,942**			

Notes: PHMSA Incident Data filtering for onshore incidents. Total incident damages include value of lost gas, public and private property damage, emergency response costs, and value of life ($11.8 million) and serious injury ($1,239,000) on a per incident average basis.

3.4 Pipeline Inspection Following Extreme Weather Events

3.4.1. Baseline

The use of transmission pipelines to transport natural gas from production to distribution pipelines, particularly in low-lying areas such as the Gulf Coast, exposes the natural gas transmission infrastructure to the risks associated with extreme weather, such as flooding, hurricanes, and erosion. While many pipelines are buried underground, exposed pipeline valves, pumping stations, and river crossings, may be particularly vulnerable to extreme weather (Cruz and Krausmann 2013).

Research suggests extreme weather is likely to become more problematic in the future. A report by Argonne National Laboratory's Environmental Science Division explains that "pipelines buried beneath or adjacent to rivers can be compromised over time by the erosive force of the moving water. Scouring can occur that would displace the cover materials and expose the pipe, subjecting it to additional lateral forces and possibly even causing sufficient displacement to break the pipe" (Pharris and Kolpa, 2007). According to that study, transmission pipelines, pump stations, compressor stations, processing facilities, storage tanks, metering stations, and buried distribution pipelines are highly vulnerable to natural hazards such as earthquakes, landslides, dam inundation, and particularly, flooding (Pharris and Kolpa 2007). A study conducted for the United States Geological Survey and the California Geological Survey showed that there have also been many pipeline failures due to ground shaking (Porter et al. 2011).

According to the IPCC and EPA reporting,[34, 35] across most of the U.S., the heaviest rainfalls have become heavier and more frequent. The amount of rain falling on the heaviest rain days has also increased over the past few decades, and there has been an increase in flooding events in the Midwest and Northeast where the largest increases in heavy rain amounts have occurred. Additionally, the intensity, frequency, and duration of North Atlantic hurricanes, as well as the frequency of the strongest hurricanes, have all increased since the early 1980s (Kossin et al 2017). With regard to tornados, activity in the United States has become more variable, with a decrease in the number of days per year with tornadoes but an increase in the number of tornadoes on these days. As sea levels have risen, the number of "nuisance floods" have increased 5- to 10-fold since the 1960s in many coastal cities, with rates accelerating in some places. In particular, Atlantic and Gulf Coast cities with extensive gas transmission pipelines networks are extremely vulnerable.

From 2010 through September 2018, pipeline operators reported 85 incidents in which storms or other severe natural forces damaged onshore gas transmission pipelines. For example, in Incident #20170006, an employee arrived on site to discover that extreme cold of -15˚ F caused the relief valve at a compressor station to open, causing $10,884 in damage.[36] In another example, Hurricane Irene eroded several hundred feet of creek bank in New York, damaging a pipeline. This incident caused $115,000 in damage and $504,000 in repair costs.[37]

There are no recorded direct- deaths or injuries from natural force incidents, but material damages and evacuations are fairly common. Operators reported total damages for these incidents at $28 million, not including operator property damage or repair costs. These incidents include pipeline accidents caused by

[34] EPA, 2021. Climate Change Indicators: Heavy Precipitation. https://www.epa.gov/climate-indicators/climate-change-indicators-heavy-precipitation#ref1
[35] USGCRP (U.S. Global Change Research Program). 2017. Climate science special report: Fourth National Climate Assessment, volume I. Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock, eds. https://science2017.globalchange.gov. doi:10.7930/J0J964J6.
[36] PHMSA, "Pipeline Incident Flagged Files: Gas Transmission Incident #20170006," available at https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files.
[37] PHMSA, "Pipeline Incident Flagged Files: Gas Transmission Incident #20110370," available at https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files.

earth movements, heavy rains, floods, extreme temperatures, high winds, lightning, or other extreme weather and natural force events.

PHMSA anticipates that prompt inspection and repair will result in operators preventing or mitigating the consequences of pipeline failures that could result in releases or incidents. Inspections following extreme weather events allow operators to detect hazardous conditions, such as exposed pipeline in waterways during flooding; earth movement around the pipeline from an earthquake; damage due to a buildup of ice or snow; damage due to fire, lightning, or wind; and submersion of equipment critical for safe operation of the pipeline. In some cases, the inspection may help detect conditions, such as erosion, that threaten pipeline integrity. Such detection could help prevent a release from occurring. Even in cases where the inspections do not prevent a release from occurring, prompt assessment of condition on the ground may accelerate deployment of response personnel and equipment, reduce safety risk, and limit damages to the surrounding environment.

PHMSA's incident record shows incident discovery and reporting after extreme events can occur after lengthy delays. PHMSA evaluated whether operators have historically conducted inspections promptly following an extreme weather event. PHMSA compared operators' official incident identification and repair times to the National Oceanic and Atmospheric Administration's (NOAA) published historical end time of extreme weather events. PHMSA identified many instances in which operators took longer than 72 hours to identify leaks or ruptures and take prompt remedial actions following an extreme weather event.

For example, after several days of extreme cold and blizzard conditions occurring in Middlesex County, Massachusetts, on February 10, 2015, (National Centers for Environmental Information 2017), a pipeline operator identified a leak. However, the operator took several weeks to take remedial actions to fix the frozen relief valve.[38] This incident caused $52,835 in damages and $3,018 in repair costs. In another instance, an operator discovered corrosion believed to be caused by Hurricane Katrina, yet they filed a report two years after the storm.[39] There are other incidents reported in which, despite Hurricane Katrina's weakening and dissipation, operators took up to a week to identify accidents.[40] In the Orange County, New York, incident #20110370 discussed above, severe thunderstorms and convection systems caused flash flooding the week before the incident and likely exacerbated the corrosion caused by Hurricane Irene the following week.

API commented on the extreme weather events provision through Section 3.8 of the ICF Study (Revised Cost for Pipeline Inspection Following Extreme Events for Transmission Pipeline). The ICF Study contends that PHMSA failed to account for the costs associated with inspections following extreme weather events. ICF assumes that 200 to 400 miles could be affected per year and with a cost per mile of inspection of $350 to $500 dollars. ICF does not provide a basis for its assumptions, but PHMSA considers the cost estimate reasonable. However, PHMSA notes that the existing regulations (§ 192.613) already required assessment procedures after extreme weather events. This Final Rule only specifies that operators conduct those inspections within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and it added section (c) to specify "extreme weather." Therefore, pipeline operators were already required to perform inspections following extreme weather events. The revisions in the final rule do not affect the number of inspections; they merely specify the timing by which those inspections must occur. There is simply no

[38] PHMSA, "Pipeline Incident Flagged Files: Gas Transmission Incident #20150028," available at https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files.
[39] PHMSA, "Pipeline Incident Flagged Files: Gas Transmission Incident #20070080," available at https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files.
[40] PHMSA, "Pipeline Incident Flagged Files: Gas Transmission Incident #20050102 & 20050107," available at https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files.

support in the record for the assumption that there will be an additional 200-400 miles of pipeline inspected as a result of this regulatory change.

3.4.2. Costs

PHMSA assumes that 50 percent of gas transmission pipeline operators already employ final rule-compliant inspection, surveillance, and survey procedures after extreme events.[41] This assumption was based on PHMSA's best professional judgment. Based on 1,060 total operators filing annual reports in 2018, PHMSA estimates that 530 will engage in compliance activity under this provision to update their procedures for extreme events pursuant to the specifications outlined above. Compliance activities include reviewing existing surveillance and patrol procedures to validate adequacy for extreme events, creating surveillance and patrol procedures, and providing personnel with implementation guidance and instruction. PHMSA assumes that the remaining 50 percent (530 operators) will undertake minor or no revisions to their procedures and programs, and that they are therefore compliant in the baseline.

Given the uncertainty in the labor estimates required to comply with this provision, PHMSA specifies a range of values and carries forward the average of these two cost values for estimating the total cost of the provision for affected operators. As illustrated in Exhibit 14, operators incurring incremental compliance costs are assumed to require 12 to 34 hours to update their procedures following extreme weather and natural disaster events. PHMSA did not receive any comments on the number of operators impacted or hours required to update programs in the PRIA.

Some commenters stated that the PRIA did not consider the cost associated with inspections on the associated miles of pipe that is impacted by an extreme event. However, current regulations in § 192.933 require operators to take remedial measures upon discovery of an unsafe condition. When operators discover an unsafe condition, they must already inspect, address, and mitigate the threat to pipeline integrity. Therefore, PHMSA expects those costs to be minimal because the requirement to inspect and remediate the threat currently exists in the regulations. Section § 192.613 only requires a more timely inspection and surveillance of pipelines in the wake of an extreme event to discover damage before the pipeline fails.

Exhibit 14 presents PHMSA's estimated one-time cost, per operator, to adjust extreme weather event procedures and programs: $1,554 per operator.

As discussed above, since operators already are required to take remedial action in the event of a natural caused pipeline accident, PHMSA did not add recurring costs to subsequent years. PHMSA applies industry- and occupation- specific labor rates to quantify operators' labor costs based on hourly wages data from the Bureau of Labor Statistics (BLS) for a Mechanical Engineer in the Gas Pipeline industry (NAICS 486200), as shown in Exhibit 2.

[41] This is consistent with PHMSA's assumption in the PRIA.

Exhibit 14: One-Time Costs for Pipeline Inspection Following Extreme Events ($2019)

Activity	*Hours Low*	*Hours High*	*Costs per Operator – Low*	*Costs per Operator – High*	*Average Cost*
Review existing surveillance and patrol procedures to validate adequacy for extreme events	2	4	$135	$270	$203
Create surveillance and patrol procedures	5	10	$338	$676	$507
Notify involved personnel of new procedures, providing implementation guidance and instruction	5	20	$338	$1,351	$844
Total per Operator	**12**	**34**	**$811**	**$2,297**	**$1,554**

Notes:
1. Hourly estimates are based on PHMSA best professional judgement.
2. Costs are based on mean hourly wages for a Mechanical Engineer as reported, adjusted for total compensation, as reported in the BLS Occupational Employment Statistics for the Pipeline Transportation of Natural Gas Industry (U.S. BLS, 2019; U.S. BLS, 2019).

Exhibit 15 presents total, undiscounted one-time costs for 530 operators to comply with the extreme weather and natural disaster event requirements. This includes $823,447 in one-time costs incurred in 2021, based on 530 operators and the estimated per-operator cost.

Exhibit 15: Total Undiscounted Extreme Weather Event Cost ($2019)

	One-Time Cost (Year 1)
Baseline	$0
Final Rule	$823,447

Notes: The one-time cost is based on the per-operator cost from Exhibit 14 multiplied by 530 operators.

Exhibit 16 shows the net present value and annualized costs, based on 3 percent and 7 percent discount rates. Given the event is a one-time event in the first year, the present value of the costs as of 2021 is equal to the undiscounted value. Annualized over 20 years, this is equivalent to $55,349 to $77,728 per year.

Exhibit 16: Extreme Weather Event Net Present Value & Annualized Cost, Year 1 – 20 ($2019)

Discount Rate	*3% Discount Rate*	*7% Discount Rate*
Net Present Value	$823,447	$823,447

Annualized	$55,349	$77,728

Notes: 1. NPV of costs from Year 1 – Year 20 reported as of January 1, 2021. Annualized value reported over same period.
2. For purposes of estimating NPV and annualized costs, costs are assumed to occur at the beginning of each period.

3.4.3. Benefits

The extreme weather event revisions specified in the final rule are aimed at reducing risk by ensuring the timely identification and remediation of pipeline problems following extreme weather and natural disaster events. More prompt attention to these potential incidents may reduce the number of pipeline failures, thereby reducing the frequency of releases and incidents, and/or mitigate the safety and environmental consequences from those releases and incidents that still do occur.

PHMSA has no data with which to quantify how releases or incident rates will change as a result of this provision. PHMSA can review historical incident data, which the rule is intended to reduce. Exhibit 17 summarizes the 108 natural-force incidents that have occurred since 2010, along with average per-incident damages, including average property damages per incident. No deaths and 2 injuries have been reported for these incidents. Apart from unquantified environmental impacts associated with releases and incidents, these incidents resulted in an average of nearly $1.2 million in total damages per incident.

Exhibit 17: Incidents Caused by Natural Force (i.e. Extreme Weather), 2010 – 2021 ($2020)

Year	*Number*	*Total Property Damages ($2021)*	*Deaths (# of persons)*	*Injuries (# of persons)*
2010	*6*	*$678,312*	*0*	*0*
2011	*18*	*$11,125,437*	*0*	*0*
2012	5	$2,079,036	0	0
2013	7	$3,967,024	0	0
2014	13	$11,896,984	0	0
2015	12	$7,371,097	0	0
2016	6	$570,469	0	0
2017	4	$8,860,789	0	0
2018	13	$40,189,103	0	0
2019	10	$23,700,153	0	2
2020	5	$16,367,004	0	0
2021	9	$1,535,887	0	0
Total	**108**	**$128,341,296**	**0**	**2**
Average	**9.00**	**$10,695,108**	**0.00**	**0.17**
Total Damages Per Incident	**$1,211,290**			

Notes: PHMSA Incident Data filtering for onshore incidents. Total incident damages include value of lost gas, public and private property damage, emergency response costs, and value of life ($11.8 million) and serious injury ($1,239,000) on a per incident average basis.

3.5 Repair Criteria

3.5.1. Baseline

In gas transmission pipelines, immediate, monitored, and 1-year or 2-year condition repairs are repairs that result from ILI, ECDA, and other inspection techniques used by operators. In all cases, operators

must notify PHMSA of the repair and take additional mitigating actions in the event the repair cannot be completed within the mandated deadline.

According to sections 3.1 (Missing Cost for MCA[42] Field Repair of Damages for Transmission Pipeline) and 3.2 (Missing Cost for non-HCA and non-MCA Field Repair of Damages for Transmission Pipeline) of the ICF study, the proposed rule (192.933) states HCA mileage must accelerate the timeframe for repair conditions under the integrity management program. This is not accurate, since PHMSA did not change immediate or one-year repair timeframes for HCA miles. Additionally, the ICF report also claims that PHMSA requires Moderate Consequence Areas (MCA) mileage to be assessed and repaired under a proposed accelerated timeframe, similar to HCA mileage through integrity management. This is not exactly accurate, since the window for required non-HCA repairs were required to be made "as soon as feasible," which was revised to be within 2 years in this Final Rule. This does not represent an accelerated repair timeline as claimed in the ICF study, since the two years should allow for repairs already required to be completed "as soon as feasible." Section 192.933 better defined criteria for crack repair, with the 1 year already being in the code, and engineer analysis was also pre-existing, PHMSA simply added what is acceptable to meet this requirement.

Under section 3.4 of the ICF study (Missing Cost for Repairing Known Existing Conditions in Transmission), the ICF Study claims that the proposed rule's changes to 192.713 require operators to repair pipeline conditions under a specified timeframe after the discovery of conditions. The ICF Study also claims that under normal business practices, companies have been making repairs to some conditions, while monitoring other conditions. ICF's interpretation is that a portion of this backlog of conditions that have not been repaired, but are being monitored, will have to be repaired immediately under the new rule. This is not accurate, since operators do not need to run the pipeline assessment tools immediately, but according to 192.710, would have 14 years to initially assess MCA pipelines (with no time period stipulated for non-MCA/HCA mileage), after which an anomaly finding would result in either an immediate or two-year window, or required monitoring until the next assessment, based on the severity of the anomaly.

Finally, section 3.7 (Revised Cost for Field Repair of Damages for Transmission Pipeline) is based on inaccurate assumptions, since "immediate" repairs for HCAs were required under § 192.933 prior to this rulemaking. Instead of allowing anomalies to grow to an immediate repair condition, PHMSA added a safety factor for remediating anomalies prior to those becoming an immediate repair in HCAs in Class 2, 3, and 4 locations (Class 1 assessments remain unchanged by this Rule). Under the pre-existing regulatory requirements, if conditions discovered require immediate repairs, such an urgent action would be incumbent regardless.

Integrity Management Repair Criteria Section §192.933

Section 192.933(d)(1) currently requires operator's evaluation and remediation schedules to follow ASME/ANSI B31.8S, when addressing immediate repair conditions. ASME/ANSI B31.8S addresses metal loss defects, stress corrosion cracking, and metal-loss affecting a detected longitudinal seam, and selective seam corrosion. Additionally, existing regulations require operators to address other indications and defects that in judgement of the operator require immediate action or dent that indicate of metal loss, cracking or a stress. PHMSA is adopting requirements to list these conditions referenced in ASME/ANSI B31.8S explicitly in the CFR. Therefore, the final changes to §192.933(d) addressing metal loss, stress

[42] A MCA is defined in § 192.3 as an onshore area within a potential impact circle, as that term is defined in § 192.903, containing either (1) 5 or more buildings intended for human occupancy or (2) any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1.

corrosion cracking, and metal-loss affecting a detected longitudinal seam, and selective seam corrosion will not impose an additional cost burden on pipeline operators since they are already required. PHMSA expects these new requirements clarify existing regulatory expectations when they are identifying immediate conditions and repairing pipeline segments in HCA locations.

For one-year conditions, operators are currently required to address two types of defects:

1. A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter; and
2. A dent with a depth greater than 2 percent of the pipeline's diameter.

In the final rule, PHMSA is finalizing four additional one-year conditions, metal-loss, one-year repair criteria beyond current CFR requirements. PHMSA discusses the changes to the baseline for one-year conditions in section **5.5.2**.

Non-Integrity Management Repairs §192.711

Under current regulations, § 192.711 requires pipeline operators to make permanent repairs as soon as feasible. However, no specific repair criteria are detailed, and no specific timeframe or pressure reduction requirements are provided in the current regulations. PHMSA determined that more specific repair criteria are needed in § 192.933(d) for pipelines not covered under IM regulations. The final rule amends paragraph § 192.711(b)(1) to require operators remediate specific conditions, as defined in new § 192.714, on non-HCA gas transmission pipelines but it does not change the requirement in § 192.711 that operators make these repairs. Given these baseline conditions, the new requirements provide more clarity when making non-IM repairs in non-HCA location, and do not impose an additional cost burden on pipeline operators.

Permanent Field Repairs of §192.714

Currently in §192.933(c) directs operators to follow the remediation schedule in ASME/ANSI B31.8S to determine the repair criteria upon discovery of a condition. The ASME/ANSI B31.8S standard applies to all onshore pipeline systems constructed with ferrous materials and that transport gas. ASME/ANSI B31.8S describes both the process and requirements in which pipeline operators assess and mitigate risks to reduce both the likelihood and consequences of incidents. The processes and requirements in ASME/ANSI B31.8S are not prescriptive to only HCA pipelines. These recommended practices may also cover non-HCA pipelines included in an IM program.

Like the HCA criteria, ASME/ANSI B31.8S establishes immediate, scheduled, and monitored conditions discovered during a pipeline inspection. For example, indications requiring immediate response are those that might cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. Corroded areas that have a predicted failure pressure level less than 1.1 times the MAOP as determined by ASME/ANSI B31G or equivalent are categorized as immediate threat, the same requirement PHMSA is adopting in a new § 192.714(d)(1).

Given these baseline requirements, PHMSA determined that the rule will not impose new requirements or costs for these repairs.

3.5.2. Costs

PHMSA's revisions to § 192.933(d)(2) are expected to impose costs compared to existing requirements for remediation of four metal-loss, one-year repair criteria, listed below: [43]

- Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b);
- Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure, determined in accordance with § 192.712(b);
- Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d); and,
- A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d).

The final rule will require operators to accelerate repairs on certain types of one-year repair conditions. PHMSA estimated the expected number of one-year gas transmission defects detected each year based on HCA miles and assessment and repair condition discovery data submitted in gas transmission and hazardous liquid annual reports. Under current regulations, HCA segments must be re-assessed every seven years. Therefore, the average annual mileage assessed is one seventh of total HCA mileage annually. Given potential overlap with HCA miles subject to MAOP reconfirmation under PHMSA's final rule titled, "Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expanded Assessment Requirements, and Other Related Amendments,"[44] PHMSA subtracted these miles from this cost analysis. PHMSA estimates 2,599 miles of HCA lines may be impacted annually (Exhibit 18).

Exhibit 18: HCA Miles Affected by Repair Criteria

Category	***Quantity of Miles***
Total HCA	20,553
Total HCA MAOP reconfirmation under Safety of Gas Transmission (RIN-1)	(2,358)
Total HCA Impacted Miles	18,195
Average Impacted per year	**2,599**

Notes: Total HCA Impact Miles divided by the 7-year assessment cycle is used to derive the 2,599 miles impacted per year.

[43] In some cases, the repair timeframe might extend beyond the next assessment deadline, and might not be repaired before the subsequent assessment, in which case the anomaly would be reevaluated.
[44] In the 2019 Gas Transmission Rule, PHMSA finalized an ECA method for operators to use as a part of the pipeline material property and attribute verification under § 192.607 and the MAOP reconfirmation requirements of § 192.624. A key element of that ECA method is the detailed analysis of the remaining strength of pipe with known or assumed defects; the 2019 Gas Transmission Rule created a new section, § 192.712, to address the techniques and procedures an operator could use to evaluate the predicted failure pressures for pipe with corrosion metal loss and cracks or crack-like defects so as to determine the remaining life of a pipeline with such defects. In this final rule, PHMSA is building on the provisions it promulgated in the 2019 Gas Transmission Rule by allowing operators to use such the same analysis for determining the timing of certain anomaly repairs, including dents. PHMSA acknowledges that the overlap between the compliance obligations under §§ 192.933(d)(2) and 192.712 were addressed in neither the 2016 PRIA (which did not contemplate § 192.712), nor the 2019 Gas Transmission Rule (as revisions to 192.933(d)(2) were beyond the scope of that rulemaking).

PHMSA estimates that approximately 81 percent of scheduled repair conditions will be one-year conditions. However, gas transmission operators do not currently report one-year conditions separate from other scheduled repairs. Therefore, to estimate the number of one-year conditions that may occur on the regulated segments, PHMSA used hazardous liquid 180-day repair conditions as a proxy. Since the new repair criteria are similar to those for hazardous liquid pipelines, PHMSA assumed that a similar proportion of gas transmission scheduled conditions would be classified as 180-day conditions, and due to their similarity PHMSA used the latter as a proxy for the former, given the lack of better options.

Exhibit 19: Estimated Scheduled Repair Conditions Rates, Hazardous Liquids, 2004 – 2009

Year	*Total Assessment Miles completed in Year*	*HCA 60-day Condition Repairs*	*HCA 180-day Condition Repairs*	*HL 60-day repair rate (conditions / mile)*	*HL 180-day repair rate (conditions / mile*	*Total HCA HL Scheduled Repairs (conditions / mile)*
2004	65,565	647	3,178	0.010	0.04	0.06
2005	17,501	1,109	5,278	0.063	0.30	0.36
2006	12,411	861	2,748	0.069	0.22	0.29
2007	9,240	579	2,139	0.063	0.22	0.29
2008	5,916	1,022	4,037	0.173	0.68	0.86
2009	3,372	441	3,088	0.135	0.92	1.05
Total	**114,005**	**4,673**	**20,468**	**0.041**	**0.40**	**0.49**

Source: PHMSA 2019a. The repair rate is calculated by dividing the total condition repairs by the miles assessed. The Total HCA HL Scheduled Repairs is the 60-day repair rate plus the 180-day repair rate.

Exhibit 20 presents the number of scheduled repair conditions over the period of 2004 – 2009, and the percent of total scheduled repair conditions these two types represent. Its estimated 180-day conditions represent 81 percent of total conditions while 60-day conditions represent 19 percent of total conditions.

Exhibit 20: Hazardous Liquid Scheduled Repair Conditions, 2004 - 2009

Repair Conditions	*Number*	*Percent of Total*
60-day conditions	4,673	19%
180-day conditions	20,468	81%
Total	25,141	100%

Note: These are the totals from Exhibit 19.

Exhibit 21 shows the total assessments completed each year and the number of immediate and scheduled repair conditions discovered as a result of those assessments. By dividing the HCA scheduled repairs conditions by the total assessments and taking the average of each year’s scheduled repair rate, PHMSA estimates operators make about 0.11 repairs per mile of pipeline assessed. In other words, operators discover one repair condition on gas transmission pipelines for every 10 miles of pipeline assessed.

Exhibit 21: Gas Transmission Integrity Management Scheduled Repair Rate, 2004 – 2009

Calendar Year	*Total Assessments Completed in Year (miles)*	*HCA Immediate Repairs*	*HCA Scheduled Repairs*	*Scheduled Repair Rate (repairs / mile)*
2004	3,998	104	599	0.15
2005	2,907	261	378	0.13
2006	3,501	158	344	0.10
2007	4,663	258	452	0.10
2008	2,858	181	252	0.09
2009	3,288	144	266	0.08
Total	**21,215**	**1,106**	**2,291**	**0.11**

Based on the prior estimate of 2,599 HCA miles assessed per year, PHMSA estimates a total of 281 repair conditions per year. Of those, 228 repairs (81 percent) are assumed to be 180-day conditions (Exhibit 22).

Exhibit 22: Number of 180-day Repair Conditions per Year

Component	*Value*	*Unit*
HCA miles assessed per year	2,599	miles / yr.
Scheduled repair conditions per mile assessed	0.11	conditions / mile
Expected scheduled repair conditions per year	281	conditions /yr.
180 conditions % of schedules conditions	81%	%
Expected 180-day conditions per year	228	conditions / yr.

Source: PHMSA 2019a, PHMSA 2019b, Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expanded Assessment Requirements, and Other Related Amendments.

Repair costs are the costs necessary to safely restore property to its predefined level of service. The cost to repair a crack or crack-like defect depends in large part on the size of the pipe, the areas to be repaired, the type of repair, and location. Crack anomalies may be repaired by sleeve, or complete pipe replacement. PHMSA used part D from the incident report form F7000.2-2014 to estimate repair costs from all onshore, HCA incidents caused by a crack or crack-like defect from 2010 – 2018. Exhibit 23 presents the incidents used to estimate repair costs, which average $120,884 per repair.[45]

[45] PHMSA has used the cost associated with repair of a crack as a conservative proxy for repairs of other types of anomalies. The cost of any repair depends largely on location (urban, rural, marsh, dry area, water crossing) and pipe diameter; other, less significant cost factors include excavation, assessment, repair method (type sleeve, recoating), and site remediation (backfill). For most of these factors, the costs of crack repair and repair of anomalies will be the same. However, the repair method for cracks will generally be the same or higher than for those other anomalies, as repair of a crack will often necessitate the repair of an underlying condition (corrosion, etc.) as well as the crack location itself.

Exhibit 23: Average Repair Costs for Cracked Pipe in HCAs, 2010 – 2018 ($2019)

Year	*Number*	*Repair Costs*	*Total Damages*
2010	1	$2,188.37	$22,548.56
2011	0	$0.00	$0.00
2012	4	$582,952.02	$747,031.30
2013	0	$0.00	$0.00
2014	3	$179,529.84	$329,315.99
2015	1	$341,432.34	$351,565.26
2016	2	$246,835.17	$288,588.92
2017	0	$0.00	$0.00
2018	0	$0.00	$0.00
Total	11	$1,352,937.74	$1,739,050.02
Average	**1.2**	$122,994.34	$158,095.46

The incremental cost for repair criteria is based on the difference in the present value of performing the one-year repairs beginning in 2020. Annual costs were estimated as the product of the 228 conditions per year and the cost per repair, $122,994, generating an annual cost of approximately $28 million. In the baseline, these costs begin in year 2025. In the final rule's implementation scenario, these costs begin in year one following the effective date. The accelerated repairs result in an incremental cost of $40 - $67 million, on a total present value basis, or $2.7 - $6.3 million per year on an annualized basis (Exhibit 24).

Exhibit 24: Repair Criteria Net Present Value & Annualized Cost, Year 1 - Year 20 ($2019)

Discount Rate	*3% Discount Rate*	*7% Discount*
Net Present Value	$40,543,261	$67,348,861
Annualized	$2,725,144	$6,357,256

Notes:
1. NPV of costs from 2021-2040 reported as of January 1, 2021.
2. For purposes of estimating NPV and annualized costs, costs are assumed to occur at the beginning of each period.

3.5.3. Benefits

Clarifications to of pipeline repair criteria are beneficial to the continuous improvement of IM. Additionally, these clarifications emphasize the functions that must be accomplished, elaborate on the elements of effective processes, and clearly articulate PHMSA's expectations. The final rule's revisions integrity assessments and the remediating anomalies identified during these assessments are expected to improve public safety and protect the environmental by preventing pipeline failure that could result in releases or incidents. PHMSA expects that emphasizing and clarifying these aspects of IM by incorporating them into the final rule text may improve operator implementation of existing IM requirements.

PHMSA does not have specific data with which to quantify the estimated safety or environmental benefits of accelerated repairs. Exhibit 25 summarizes the 1,260 incidents since 2010, along with average per-incident damages, including average property damages, deaths and serious injuries per incident. These incidents resulted in an average of $1.6 million in total damages per incident. This rule will improve safety and reduce the prevalence of incidents summarized in Exhibit 25.

Exhibit 25: Onshore Gas Transmission Incidents, 2010 - 2021

Year	*Number*	*Total Property Damages ($2021)*	*Deaths (# of persons)*	*Injuries (# of persons)*
2010	84	$691,482,894	10	61
2011	105	$124,606,120	0	1
2012	89	$55,337,671	0	7
2013	96	$49,990,567	0	2
2014	120	$51,753,471	1	1
2015	132	$60,535,559	6	16
2016	86	$112,844,536	3	3
2017	103	$42,875,918	3	3
2018	112	$78,276,395	1	5
2019	119	$103,899,696	1	8
2020	119	$63,085,559	2	2
2021	95	$53,217,485	4	4
Total	**1260**	**$1,487,905,869**	**31**	**113**
Average	**105.00**	**$123,992,156**	**2.58**	**9.42**
Total Damages Per Incident	**$1,582,312**			

Notes: PHMSA Incident Data filtering for onshore incidents. Total incident damages include value of lost gas, public and private property damage, emergency response costs, and value of life ($11.8 million) and serious injury ($1,239,000) on a per incident average basis.

3.6 Total Costs

Exhibit 26 summarizes the total incremental costs of the final rule over the 20 year analysis period. Exhibit 27 presents annualized costs for the final rule. Total costs are estimated to be $188 to $176 million over the 20-year analysis period. On an annualized basis, the final rule has incremental costs of $12.6 - $16.7 million per year.

Exhibit 26: Present Value of Incremental Cost, Year 1 - Year 20 ($2019 USD thousands)

Provision	*Discount Rate*	
	3%	*7%*
Integrity Management*	$0	$0
MoC Process Improvements	$17,768	$12,953
Corrosion Control	$128,865	$95,327
Extreme Weather	$823	$823
Repair Criteria	$40,543	$67,349
Total	**$188,000**	**$176,452**

*No incremental costs are estimated for this topic area.

Exhibit 27: Annualized Cost of the Final Rule ($2019 USD thousands)

Provision	*Discount Rate*	
	3%	*7%*
Integrity Management*	$0	$0
MoC Process Improvements	$1,194	$1,223
Corrosion Control	$8,662	$8,998
Extreme Weather	$55	$78
Repair Criteria	$2,725	$6,357
Total	**$12,637**	**$16,656**

*No incremental costs are estimated for this topic area.

3.7 No Action Alternative

Under the No Action Alternative PHMSA does not expect any changes from baseline environmental impacts to human health, the physical environment, or environmental justice. If the No Action Alternative were selected, the changes aimed at reducing pipeline failure would not be implemented or achieved. As described above, the final rule is designed and expected to reduce the frequency and consequences of natural gas transmission pipeline failures, which can result in releases or incidents emitting large amounts of methane (and, if that methane combusts, carbon dioxide). The final rule is expected to accomplish this goal, in part, by requiring repairs of detected anomalies. The final rule is expected to require more frequent repairs than under the No Action Alternative, but in doing so would reduce the frequency and consequence of pipeline releases and incidents.

Some of these repairs, especially repairs for internal corrosion, could necessitate the pipeline operator to evacuate natural gas from sections of affected pipe to repair the pipeline safely, which could require the flaring (i.e. burning, resulting in carbon dioxide emissions) or blowing down (i.e. releasing unburned methane) of that natural gas. When a pipeline operator must evacuate a pipeline segment for a repair, it typically either installs a repair sleeve or cuts out a section of the pipe. To cut out a section of pipe the operator reduces the pipeline pressure and isolates the section by closing the nearest block valves or by utilizing a stopple and removing gas from that section. In these instances, a release of GHGs will occur, though much smaller than a release that would result from a pipeline failure. The amount of carbon dioxide or unburned methane released to evacuate the pipeline would depend on the size and pressure of the isolated section of pipe. On the other hand, many pipeline maintenance and repair activities do not require flaring or blowdown, such as cathodic protection adjustments, coating repairs, and some repairs to the pipeline itself.

3.8 Uncertainties and Limitations

PHMSA acknowledges uncertainty in its analysis of the costs and benefits related to underlying elements of the analysis, including in particular the unit costs for compliance actions and the overall effectiveness and associated value of avoiding future incidents.

As described for provisions detailed throughout this section, 5, PHMSA’s analysis relies in several instances on assumptions about the degree to which operators are already undertaking actions that are consistent with the final rule’s requirements (i.e., baseline compliance) as well as the quantity of labor and other drivers of the rule’s costs. Key sources of uncertainty in this regard include:

- **Management of Change –** There is uncertainty with respect to the proportion of operators that already have compliant MoC processes, and the operator labor required, for non-compliant operators, to develop and implement MoC processes. Similarly, the analysis assumes a fixed number of events per year.
- **Extreme Weather Events** – There is uncertainty in the assumed proportion of operators that will need to make additional updates to their extreme weather and natural disaster event processes, and the quantity of labor required to make those updates for affected operators.
- **Corrosion Control –** There is uncertainty in the assumed proportion of operators that will require incremental compliance action (behavior change) for CIS and Interference Surveys. There is similar uncertainty in the assumed number of coating surveys performed annually.

PHMSA uses a static inventory of the pipeline infrastructure for its analysis, based on data from 2017. While historical data indicate that changes in pipeline infrastructure happen slowly over time, to the extent there is significant pipeline construction in the future to service new areas and the final rule results in additional requirements for these new lines (e.g., additional reporting), the analysis understates the potential costs and benefits.

There is also substantial uncertainty in the analysis of benefits, with respect both to the effectiveness of compliance actions in mitigating future pipeline failures (and thus the frequency and severity of releases and incidents), and the beneficial value of avoiding such failures. The benefits of the final rule depend on whether compliance actions result in additional safety measures, and the effectiveness of those measures in preventing or mitigating future pipeline failures. The primary quantifiable benefits in the final rule are the estimated number of pipeline failures resulting in releases and incidents that would be averted by implementing the rule's provisions. For the final rule RIA, PHMSA did not monetize benefits. The final rule's benefits are discussed qualitatively.

4 Analysis Required Under Applicable Statutes or EOs

This section describes administrative requirements for regulatory analyses and summarizes PHMSA's findings for the final rule.

4.1 Executive Order 12866: Analysis of Costs and Benefits

Under EO 12866, PHMSA must determine whether the regulatory action is "significant" and therefore subject to review by OMB and other requirements of the EO. The order defines a "significant regulatory action" as one that is likely to result in a regulation that may:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the EO.

This action has been determined to be significant under Executive Order 12866.

4.2 Regulatory Flexibility Act (RFA)

The Regulatory Flexibility Act (RFA) of 1980, as amended, requires Federal agencies to consider the impact of their rules on small entities, analyze alternatives that minimize those impacts, and make their analyses available for public comments. The RFA is concerned with three types of small entities: small businesses, small nonprofits, and small governmental jurisdictions.

The RFA describes the regulatory flexibility analyses and procedures that Federal agencies must complete unless they certify that the rule, if promulgated, would not have a significant economic impact on a substantial number of small entities. A statement of factual basis must support this certification (e.g., through addressing the number of small entities affected by the action, calculating expected cost impacts on these entities, and evaluating economic impacts).

PHMSA prepared a FRFA, which is available in the docket for this final rule. Costs fall in the range of one to three percent of sales for 13 to 15 small entities (3 percent of all small entities) and may exceed three percent of sales for 49 to 53 small entities (11 percent).

Given the number and percentage of small businesses affected PHMSA determined that the final rule will not have a significant impact on a substantial number of small entities.

4.3 Unfunded Mandates Reform Act (UMRA)

Section 201 of the UMRA (2 U.S.C. 1531), requires that Federal agencies assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under UMRA § 202, PHMSA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that might result in expenditures by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million (adjusted annually for inflation) or more in any one year.

Based on the cost estimates detailed in section 5, PHMSA determined that compliance costs for any State, local, and Tribal government, in the aggregated, or private sector in any given year will be below the threshold set in UMRA.

4.4 Paperwork Reduction Act (PRA) of 1995

The PRA (5 U.S.C. 1320.3), as implemented by OMB, requires that agencies submit a supporting statement to OMB for any information collection that solicits the same data from ten or more parties. The PRA seeks to ensure that Federal agencies balance their need to collect information with the paperwork burden imposed on the public by the collection.

Under the PRA, the definition of "information collection" includes activities required by regulations, such as permit development, monitoring, recordkeeping, and reporting. The term "burden" refers to the "time, effort, or financial resources" the public expends to provide information to a Federal agency, or to otherwise fulfill statutory or regulatory requirements. The PRA paperwork burden is measured in terms of annual time and financial resources the public devotes to meet one-time and recurring information requests (44 U.S.C. 3502(2); 5 CFR 1320.3(b)). Information collection activities may include:

- Reviewing instructions;
- Using technology to collect, process, and disclose information;
- Adjusting existing practices to comply with requirements;

- Searching data sources;
- Completing and reviewing the response; and
- Transmitting or disclosing information.

Agencies must provide information to OMB on the parties affected, the annual reporting burden, the annualized cost of responding to the information collection, and whether the request significantly impacts a substantial number of small entities. An agency may not conduct or sponsor, and a person is not required to respond to, an information collection unless it displays a currently valid OMB control number.

OMB has previously approved the information collection requirements contained in the existing pipeline safety regulations under the provisions of the PRA. The final rule will change the information collection requirements associated with certain gas transmission and gathering pipelines. PHMSA estimates the reporting and recordkeeping burden for provisions in § 4, and is submitting a revised ICR to OMB for approval.

4.5 EO 13132: Federalism

EO 13132[46] requires PHMSA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." Policies that have federalism implications are defined in the EO to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

Under § 6 of EO 13132, PHMSA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments or unless PHMSA consults with State and local officials early in the process of developing the regulation. PHMSA also may not issue a regulation that has federalism implications and that preempts State law, unless the Agency consults with State and local officials early in the process of developing the regulation.

PHMSA has concluded that this action does not impose substantial direct compliance costs on State or local governments.

4.6 EO 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

EO 13211 requires agencies to prepare a Statement of Energy Effects when undertaking certain agency actions. Such Statements of Energy Effects shall describe the effects of certain regulatory actions on energy supply, distribution, or use, notably: (1) any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increased use of foreign supplies) should the proposal be implemented, and (2) reasonable alternatives to the action with adverse energy effects and the expected effects of such alternatives on energy supply, distribution, and use.

The OMB implementation memorandum for EO 13211 outlines specific criteria for assessing whether a regulation constitutes a "significant energy action" and would have a "significant adverse effect on the supply, distribution or use of energy." Those criteria include:

1. Reductions in crude oil supply in excess of 10,000 barrels per day;

[46] 64 FR 43255 (Aug. 10, 1999).

2. Reductions in fuel production in excess of 4,000 barrels per day;
3. Reductions in coal production in excess of 5 million tons per year;
4. Reductions in natural gas production in excess of 25 million Mcf per year;
5. Reductions in electricity production in excess of 1 billion kilowatt-hours per year, or in excess of 500 megawatts of installed capacity;
6. Increases in the cost of energy production in excess of 1 percent;
7. Increases in the cost of energy distribution in excess of 1 percent;
8. Significant increases in dependence on foreign supplies of energy; or
9. Having other similar adverse outcomes, particularly unintended ones.

Of the potential significant adverse effects on the supply, distribution, or use of energy (listed above), only the seventh applies to the final rule (i.e., increases in the cost of energy distribution in excess of 1 percent). Though the final rule could increase the cost of distributing natural gas that serves as fuel, the cost increase is expected to be small and much less than the 1 percent threshold suggestive of potential impacts on energy supply, distribution, or use since the rule is expected to impose only existing pipelines operation and maintenance requirements. Further, OMB's Office of Information and Regulatory Affairs has not designated this final rule as a significant energy action.

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BEFORE THE
U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Pipeline Safety:	)	
Safety of Gas Transmission Pipelines:	)	
Repair Criteria, Integrity Management	)	
Improvements, Cathodic Protection,	)	**Docket No. PHMSA-2011-0023**
Management of Change, and Other	)	
Related Amendments	)	

Petition for Reconsideration
of the Interstate Natural Gas Association of America
and the American Petroleum Institute

Filed September 23, 2022

Table of Contents

I. Introduction

Pursuant to 49 C.F.R. § 190.335(a), the Interstate Natural Gas Association of America (INGAA) and the American Petroleum Institute (API) (the Associations) submit a Petition for Reconsideration (Petition) of the final rule issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued in Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, (the Final Rule) published in the Federal Register on August 24, 2022.[1]

INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 26 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA's members operate nearly 200,000 miles of pipelines and serve as an indispensable link between natural gas producers and consumers.

API is the national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and 8 percent of the U.S. economy. API's more than 600 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 25 million Americans.

The Final Rule is the last in a trilogy of final rules[2] that adopted the most significant amendments to PHMSA's Part 192 pipeline safety standards since they were first adopted in 1970. It strengthens integrity management requirements for data integration, risk assessments, and preventive and mitigative measures; adopts new repair criteria for pipelines not located in high consequence areas (HCA); revises the calculation of critical strain levels in pipe with dent anomalies or defects; revises corrosion control regulations affecting external corrosion, internal corrosion and stress corrosion cracking; modifies analysis for calculating predicted failure pressure; and extends Management of Change requirements to non-HCA pipeline segments. In addition, the Final Rule incorporates by reference into Part 192 two additional industry standards and extends provisions of previously incorporated standards into additional regulations.

Pipeline safety is the top priority of the Associations and their members. The Associations strongly support the Final Rule because the strengthened and enhanced requirements will enhance pipeline safety and help advance our industry's efforts to achieve a perfect safety and reliability record for our nation's natural gas pipelines. The Associations have publicly championed PHMSA's efforts to finalize this important rulemaking based on the consensus built through the Gas Pipeline Advisory Committee (GPAC) process

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[1] 87 Fed. Reg. 52,224 (Aug. 24, 2022).

[2] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, Final Rule, 84 Fed. Reg. 52,180 (Oct. 1, 2019) (2019 Gas Transmission Rule); Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, Final Rule, 86 Fed. Reg. 63,266 (Nov. 15, 2021).

II. Executive Summary

The Associations support the Final Rule, but files this Petition requesting that PHMSA reconsider several provisions. First, the Associations request additional time to implement the provisions of a complex rule that, while took over ten years to develop, contains several unanticipated provisions that deviated from those that were proposed or from GPAC recommendations. A nine-month effective date is not practicable or reasonable, especially given that operators also are implementing the requirements of other significant new regulatory and statutory requirements.

The Associations also seek reconsideration of provisions that departed from GPAC recommendations, some of them unanimous, without providing supporting evidence or explanation. These provisions include the requirement to treat a crack or crack-like condition as an immediate repair condition if it has a predicted failure pressure of less than 1.25 times the MAOP and the requirement that operators monitor and mitigate effects of corrosive "constituents" in a gas stream. The GPAC recommendations were the product of a substantial amount of time and effort by everyone involved, including representatives of the public, state regulators and industry. Under the Administrative Procedure Act (APA) and Pipeline Safety Act, PHMSA's rejection of the GPAC recommendations and the adoption of different regulations requires a reasoned explanation and supporting evidence.

The Associations also seek reconsideration of the requirement that operators assume a reassessment safety factor of 5 or greater for the assessment interval when evaluating dents and other mechanical damage because this provision provides no discernable safety benefit established by PHMSA, and was not proposed, presented to the GPAC, or made subject to notice and comment. Similarly, the requirement to treat metal loss associated with high-frequency electric resistance welded seams as an immediate repair condition is unsupported by evidence and PHMSA did not respond to INGAA's comments and concerns about this provision.

Finally, the Associations request that PHMSA provide guidance and clarification of several complex requirements, in order to ensure that the agency's compliance expectations are clear. The Associations also request that PHMSA make technical corrections and clarifications to several regulations that appear to contain inadvertent errors.

III. Statutory Framework

When issuing final rules adopting new safety standards, PHMSA must comply with the requirements of the APA[3] and the Pipeline Safety Act.[4] Under the APA, a Final Rule is unlawful if it is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law."[5] This determination is informed by whether PHMSA's final rule reflects reasoned decision-making under APA principles and complies with the Pipeline Safety Act.

[3] 5 U.S.C. §§ 551-559 (2018).
[4] 49 U.S.C. §§60101-60143 (2018), as amended by The Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020, Pub. L. No. 116-260, div. R, title I, § 108(a)(2), 134 Stat. 2221, 2223 (Dec. 27, 2020).
[5] 5 U.S.C. § 706(2)(A); *see Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

When issuing a final rule, PHMSA is required to "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'"[6] PHMSA's explanation for its decision "may not be superficial or perfunctory"[7] and must be consistent with the evidence.[8] A final rule is arbitrary and capricious if the agency relies "on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise."[9] In addition, PHMSA must reveal and provide the technical bases for its proposed rules and allow adequate time "for meaningful commentary" or be found in violation of the notice and comment provisions of section 553(c) of the APA.[10] A final rule that does not comply with these principles is arbitrary and capricious.

Failure to comply with the requirements of the Pipeline Safety Act also is arbitrary and capricious. Under the Pipeline Safety Act, PHMSA is charged with protecting against risks posed by pipelines by prescribing minimum safety standards for pipeline transportation and pipeline facilities.[11] PHMSA's authority to issue safety standards is constrained by the Pipeline Safety Act's requirements and proscriptions. The Pipeline Safety Act requires that a safety standard be "practicable" and designed to meet gas pipeline safety needs and protect the environment.[12] When prescribing any safety standard, PHMSA must consider relevant available gas pipeline safety information, environmental information, the appropriateness of the standard for the type of transportation or facility, reasonableness, comments and information received from the public, and comments and recommendations of the Technical Pipeline Safety Standards Committee.[13]

The Pipeline Safety Act requires that PHMSA consider, "based on a risk assessment, the reasonably identifiable or estimated costs expected to result from" implementing or complying with the standard.[14] When performing this risk assessment, PHMSA must, for each standard,

(A) identify the regulatory and nonregulatory options that the Secretary considered in prescribing a proposed standard;

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[6] *State Farm*, 463 U.S. at 43 (citing *Burlington Truck Lines v. United States*, 371 U.S. 156, 168 (1962)) (vacating as arbitrary and capricious final rule that rescinded regulations without adequate explanation).
[7] *Owner-Operator Indep. Drivers Ass'n v. FMCSA*, 656 F.3d 580, 588 (7th Cir. 2011) (applying *State Farm* standard and vacating final rule as arbitrary and capricious).
[8] *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831,839, 843 (D.C. Cir 2006) (vacating agency rule because record evidence did not support existence of the problem the rule purported to address).
[9] *State Farm*, 463 U.S. at 43 (vacating agency's rescission of regulation without adequate explanation); *Pub. Citizen v. FMCSA*, 374 F.3d 1209, 1216 (D.C. Cir 2004) (finding that agency's failure to consider statutory factor constituted a failure to consider an important aspect of the problem).
[10] *Owner-Operator Indep. Drivers Ass'n*, 494 F.3d at 199 (citing *Solite Corp. v. EPA*, 952 F.2d 473, 484 (D.C. Cir. 1991)) (finding that agency's failure to disclose the methodology of the agency's operator-fatigue model for performing a crash-risk analysis when that model was the basis for the cost-benefit analysis used in the agency's Regulatory Impact Assessment violated APA's notice and comment requirements).
[11] 49 U.S.C. § 60102(a)(1) & (2).
[12] *Id.* § 60102(b)(1).
[13] *Id.* § 60102(b)(2).
[14] *Id.* § 60102(b)(2)(E).

(B) identify the costs and benefits associated with the proposed standard;
(C) include –
 (i) an explanation of the reasons for the selection of the proposed standard in lieu of the other options identified; and
 (ii) with respect to each of those other options, a brief explanation of the reasons that [PHMSA] did not select the option; and
(D) identify technical data or other information upon which the risk assessment information and proposed standard is based.[15]

PHMSA also is required to provide "the risk assessment information and other analyses supporting each proposed standard" to the Technical Pipeline Safety Standards Advisory Committee, (*i.e.*, Gas Pipeline Advisory Committee (GPAC)), the federal advisory committee that reviews and provides recommendations on pipeline safety rulemaking proposals.[16] The GPAC is required to "prepare and submit to [PHMSA] a report on the technical feasibility, reasonableness, cost-effectiveness, and practicability of the proposed standard and include in the report recommended actions" within "90 days of receiving the proposed standard and supporting analysis."[17] PHMSA is then required to "publish each report, including any recommended actions and minority views." PHMSA is "not bound by the conclusions of the [GPAC]" on a proposed rule, but must "publish the reasons" for rejecting its conclusions.[18]

Disregarding the Pipeline Safety Act's statutorily-mandated factors and procedures when adopting a safety standard is arbitrary and capricious[19] and reflects a failure to consider an important aspect of the problem.[20] Moreover, these factors apply to each proposed safety standard, as evidenced by use of the singular noun "standard" throughout these provisions.[21]

IV. Petition for Reconsideration

Under § 190.335, any interested person may petition PHMSA for reconsideration of an issued regulation. The petition must contain "a brief statement of the complaint and an explanation as to why compliance with the rule is not practicable, is unreasonable, or is not in the public interest."[22] The Associations file this Petition to seek reconsideration of several specific

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[15] *Id.* § 60102(b)(3).
[16] *Id.* § 60115(c)(1)(A).
[17] *Id.* § 60115(c)(2)
[18] *Id.*
[19] *Owner-Operator Indep. Drivers Ass'n*, 656 F.3d at 589 (vacating rule because agency failed to consider an issue it was statutorily required to address); *Pub. Citizen*, 374 F.3d at 1216 (D.C. Cir 2004) (vacating final rule for failing to consider impact of final rule on the health of drivers, a mandatory statutory consideration under organic statute). *Id.* (stating that "'the complete absence of any discussion' of a statutorily mandated factor 'leaves us with no alternative but to conclude that [the agency] failed to take account of the statutory limit on [its] authority,'" making the agency's reasoning arbitrary and capricious.") (quoting *United Mine Workers v. Dole*, 870 F.2d 662, 673 (D.C. Cir. 1989)).
[20] *Pub. Citizen*, 374 F.3d at 1216.
[21] *C.f., Am. Fed'n of Labor and Cong. of Indus. Orgs. v. OSHA*, 965 F.2d 962, 969 (11th Cir. 1992) (finding that, where statute required agency to establish permanent exposure limits for air contaminants in the workplace based on substantial evidence of the risk the contaminants posed to workers, agency was required to demonstrate that the PEL for each contaminant was supported, and that failure to make such demonstration was arbitrary and capricious).
[22] 49 C.F.R. § 190.335(a).

issues in order to ensure that the requirements of the Final Rule are clear, practicable, and reasonable.

A. The Associations request reconsideration of the Final Rule's nine-month effective date.

The effective date of most of the provisions in the Final Rule is May 24, 2023, merely nine months after the date of publication. The Associations request reconsideration of this effective date because requiring the implementation of complex new regulatory requirements, including newly incorporated industry standards, within nine months is not consistent with pipeline safety and is not practicable or reasonable. The Associations request that PHMSA provide operators 18 months to implement the comprehensive new requirements of the Final Rule.

The scope of the Final Rule is comprehensive and broad, and as explained in the Trade Associations' June 6, 2018 comments,[23] implementing the new requirements will be complex and time-consuming. In order to realize the full safety benefits of the new requirements that were eleven years in the making, PHMSA must permit operators the time necessary to implement them correctly and carefully. The additional time also will enable PHMSA staff to develop compliance guidance for both operators and inspectors.

Compliance with the Final Rule is not simple. Processes and procedures affected by new requirements include those related to operation, maintenance, emergency, integrity management, and operator qualification programs. Amending these procedures to reflect new regulations requires that operators examine processes across their systems and understand how they are affected by new requirements. An operator must amend existing procedures to reflect new processes, and in some cases, create new procedures. Revisions to one procedure often affect other procedures that may not be directly addressed by the new regulations. Subject matter experts from across various functions and disciplines must be consulted and revised procedures must be vetted by appropriate personnel, including operating staff and management. An operator also may have to update its information technology infrastructure, including data and document management systems, to accommodate new processes. Staff must be fully trained on the new procedures and, if necessary, qualified on new covered tasks under the operator's operator qualification program. In addition, an operator must develop and implement a management of change (MOC) process before implementing new procedures and processes.

The challenges of implementing the Final Rule's new requirements are exacerbated by the fact that operators also are simultaneously working to implement the requirements of other new significant regulatory and statutory requirements. PHMSA's recently issued Valves Final Rule becomes effective October 5, 2022 and requires compliance by April 10, 2023.[24] The

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[23] Comments on Pipeline Safety: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments Final Rule, filed by the American Gas Association, American Petroleum Institute, American Public Gas Association, and INGAA, Docket Nos. PHMSA-2016-0136, PHMSA-2011-0023, at 12 (June 6, 2018) (Comments of Trade Associations).

[24] Pipeline Safety: Requirements of Valve Installation and Minimum Rupture Detection Standards, Final Rule, 87 Fed. Reg. 20,940 (Apr. 8, 2022) (Valves Final Rule).

Valves Final Rule requires that operators, among other things implement enhanced valve maintenance procedures, including annual testing and response time drills, perform risk assessments and install rupture mitigation valves in HCAs if an operator determines it would efficiently protect an HCA. An operator also must implement new emergency response and post-accident procedures. Implementing the Valves Final Rule requires examination of processes, the development of new procedures, and the dedication of the same personnel who are now are called upon to implement this Final Rule.

In addition, operators continue their efforts to implement the requirements of the 2019 Gas Transmission Rule[25] and the 2020 PIPES Act.[26] Notably, the Final Rule amends several of the same provisions that were either amended or newly adopted in the 2019 Gas Transmission Rule, requiring that operators revisit and revise their implementation of those requirements. For example, the 2019 Gas Transmission Rule adopted § 192.712 addressing the analysis of predicted failure pressure. Operators have undertaken to implement that provision's requirements by evaluating processes and revising procedures. The Final Rule has further amended § 192.712, requiring operators to evaluate how the newly adopted provisions integrate with the 2019 language. In addition, newly adopted § 192.714, establishing repair criteria for pipeline segments not located in HCAs, also interrelates with the requirements of § 192.712. Changes to § 192.933 adopted in both the 2019 Gas Transmission Rule and the Final Rule present similar challenges.

Finally, operators are also continuing to implement § 114(b) of the PIPES Act which requires that operators update their inspection and maintenance plans to address eliminating hazardous leaks, minimizing natural gas releases, and replacing or remediating pipelines known to leak.[27]

Imposing a nine-month compliance schedule, which was not subject to notice and comment, and requiring operators to rush compliance efforts does a disservice to the goal of promoting pipeline safety and is not practicable or reasonable. Nine months does not reasonably accommodate all the work required to effectively implement the new requirements of the Final Rule and does not account for the existing compliance demands already placed on an operator's staff. Nine months also does not allow PHMSA staff adequate time to develop the guidance that operators and inspectors will need for effective compliance and enforcement.

The nine-month compliance deadline also is not practicable from a financial planning perspective. Budgets for 2023, which were planned and developed months ago, are now finalized. While the Associations actively participated in the GPAC meetings and the rulemaking process, the Final Rule's unanticipated departures from a number of GPAC recommendations are not accounted for in 2023 budgets. A nine-month compliance timeframe disrupts financial planning and a company's ability to execute on other important safety initiatives and is not consistent with pipeline safety.

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[25] 84 Fed. Reg. 52,180.

[26] The Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020, Pub. L. No. 116-260, div. R, title I, § 108(a)(2), 134 Stat. 2221 (Dec. 27, 2020).

[27] 134 Stat. 2221, 2231.

For these reasons the nine-month implementation date is not practicable or reasonable. The Associations petition PHMSA to reconsider the Final Rule's nine-month implementation deadline and requests that PHMSA amend the Final Rule to provide operators 18 months from the date of publication to implement all provisions of the Final Rule.

B. The Associations request reconsideration of §§ 192.714(d)(1)(v)(C) and 192.933(d)(1)(v)(C) and requests that an operator is not required to treat a crack or crack-like condition as an immediate repair condition unless the predicted failure pressure is less than 1.1 times Maximum Allowable Operating Pressure (MAOP).

Maximum allowable operating pressure is defined as "the maximum pressure at which a pipeline or segment of a pipeline may be operated under" Part 192 of the pipeline safety regulations.[28] Sections 192.714(d)(1)(v)(C) and 192.933(d)(1)(v)(C) require that an operator of a gas transmission pipeline treat as an immediate repair condition any crack or crack-like anomaly that meets any one of several criteria, including that the anomaly "has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP."[29]

The Associations seek reconsideration of §§ 192.714(d)(1)(v)(C) and 192.933(d)(1)(v)(C) and requests that PHMSA amend the regulatory language to reflect the GPAC language which recommended a predicted failure pressure of 1.1 times MAOP. PHMSA's basis for adopting a predicted failure pressure of 1.25 times MAOP disregards the evidence supporting the GPAC recommendation, is inconsistent with existing regulations, and does not reflect reasoned decision-making.

The Final Rule acknowledges that the adopted predicted failure pressure of 1.25 times MAOP departs from the GPAC recommendation of 1.1 times MAOP after tool tolerance is verified.[30] This recommendation was unanimously agreed to after extensive discussion. PHMSA explains its decision to reject the GPAC recommendation as follows:

> PHMSA considered this suggestion but notes that, after allowing for pressure excursions above MAOP due to over pressure protection device settings, the actual safety margin of such an approach would be between 0 and 6 percent. PHMSA has determined that this safety margin for immediate crack conditions is inadequate and, for this final rule, has retained the requirement that operators must immediately repair crack anomalies with a predicted failure pressure that is less than 1.25 times MAOP.[31]

As the Associations understand this statement, PHMSA believes that a repair criterion of 1.1 times MAOP is not conservative enough because an operator has the ability to operate a pipeline segment above its established MAOP, which, in turn, reduces the safety margin associated with a predicted failure pressure. PHMSA's statement is inconsistent with multiple

[28] 49 C.F.R. § 192.3.
[29] Final Rule, 87 Fed. Reg. at 52,272, 52,277-78
[30] GPAC Meeting Final Voting Slides at 22 (March 26-28, 2018).
[31] Final Rule, 87 Fed. Reg. at 52,248.

Part 192 regulations that prohibit operating a pipeline segment at pressures higher than its MAOP and does not support PHMSA's decision to reject the GPAC recommendation. Moreover, PHMSA does not explain how it calculated a safety margin of 0 to 6 percent.[32]

Under § 192.619(a), an operator of a steel or plastic pipeline segment is prohibited from operating that segment at a pressure that exceeds its MAOP.[33] This prohibition also is reflected in numerous other provisions throughout PHMSA's Part 192 regulations. For example, under § 192.605(b)(5), an operator's written operations and maintenance procedures manual must contain a procedure addressing "[s]tarting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of operation of pressure-limiting and control devices."[34]

This build-up is allowed under § 192.201, a design regulation that governs the design of pressure relieving and limiting stations that pipelines install to prevent overpressuring a pipeline. Section 192.201(a) requires that

> Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following: . . . . (2) In pipelines other than a low pressure distribution system: (i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SYMS, whichever is lower.[35]

Section 192.201(a) applies only to pressure relieving or limiting devices and requires that they have the capacity to relieve gas in the pipeline the device is protecting should the pressure in the pipeline ever exceed MAOP plus ten percent. This design safeguard ensures that the pipeline does not rupture if operating pressure exceeds MAOP for some unintended reason. Section 192.201(a) does not govern the operation of pipelines and does not authorize a pipeline segment to operate at a pressure higher than the segment's MAOP.

The prohibition on operating a pipeline segment at a pressure that exceeds its MAOP also applies to compressor station piping. Similar to § 192.201, § 192.169(a) requires that each compressor station "have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent."[36]

PHMSA's assumption in the Final Rule that a pipeline segment is permitted to operate at pressures above MAOP via "pressure excursions above MAOP due to over pressure protection device settings,"[37] is inconsistent with long-standing regulations prohibiting a pipeline segment

[32] Agency decisions not supported by substantial evidence or do not reflect reasoned decision making are arbitrary and capricious under the Administrative Procedure Act. 5 U.S.C § 706(2)(A); *see State Farm*, 463 U.S. at 43.
[33] 49 C.F.R. § § 192.619(a).
[34] *Id.* § 192.605(b)(5).
[35] *Id.* § 192.201(a)(2)(i).
[36] *Id.* § 192.169(a).
[37] Final Rule, 87 Fed. Reg. at 52,248, 52,252.

from operating at pressures above MAOP. PHMSA's assumption is incorrect and the agency's basis for establishing a 1.25 times MAOP threshold for determining when a crack or crack-like anomaly must be treated as an immediate repair condition fails to "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'"[38]

In support of the Final Rule, PHMSA also states that it took guidance from several sources, including ASME ST–PT–011 (''Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas''). PHMSA states that:

> In this final rule, operators can use an engineering analysis on cracks in Categories 1 through 2 as described above. However, any Category 3 or 4 cracking defect below 125 percent MAOP would require immediate remediation. Category 3 cracks would have a 10 percent or greater safety factor, which is similar to how PHMSA currently treats corrosion anomalies at § 192.933. PHMSA provides more conservatism in the cracking criteria because there is more uncertainty with the accuracy of current ILI [in-line inspection] technology in its ability to measure crack length and depth, as well operational factors.[39]

PHMSA's statement that Category 3 cracks require immediate remediation is incorrect. As the Final Rule states, and as also shown in Table 40 of ASME STP-PT-011, the remaining life of a Category 3 crack at MAOP is greater than 2 years.[40] That is not an immediate condition.

In addition, PHMSA's statement that it applied more conservatism for cracking because of perceived uncertainty of current in-line inspection (ILI) technology is speculative and does not acknowledge the lengthy GPAC discussions. During the March 2, 2018 GPAC meeting on this proposal, a GPAC member pointed out that operators demonstrate the accuracy of the ILI system through tools such as unity plots.[41] Unity plots compare "as found" conditions in an excavation to conditions "as called" made by the ILI and provide a basis for demonstrating the effectiveness of an ILI and for developing appropriate tolerances based on actual field measurements. The approach agreed upon by the GPAC members after a long discussion on conservatism, including the use of unity plots, was to enable use of 1.1 x MAOP, but to require accounting for tool tolerances.[42] This approach is consistent with § 192.712(e)(1) which places the burden on an operator to "analyze and account for uncertainties in reported assessment results . . . in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using *in situ* direct measurements."[43]

Finally, when applied in conjunction with the conservative default Charpy v-notch toughness values adopted in § 192.712(e)(2)(D) for pipeline segments with a history of crack or crack-like defects (adopted in the 2019 Gas Transmission Final Rule), the conservative repair

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[38] *State Farm*, 463 U.S. at 43.
[39] Final Rule, 87 Fed. Reg. at 52,248.
[40] *Id.* at 52,249.
[41] GPAC Meeting Transcript at pp. 257-59 (March 2, 2018) (Statement of Mr. Drake).
[42] GPAC Meeting Final Voting Slides at 22 (March 26-28, 2018) .
[43] 49 C.F.R. § 192.712(e)(1).

criterion of 1.1x MAOP (accounting to tool tolerances) results in layers of conservatism for which PHMSA has provided no supporting evidence or analysis and without explanation.

The Final Rule does not reflect reasoned decision-making because it fails to address either the GPAC discussion on unity plots, the conservatism reflected in the GPAC Recommendation, or existing § 192.712(e)(1). In this respect the Final Rule is inconsistent with the evidence before the agency and fails to consider an important aspect of the problem.[44] PHMSA also failed to consider relevant available pipeline safety information and to explain the reasons for rejecting the GPAC recommendation.[45]

PHMSA also has not demonstrated that adopting a predicted failure pressure of 1.25 times MAOP is appropriate, reasonable, or practicable and does not consider the factors required under the Pipeline Safety Act.[46] The Final Rule is inconsistent with existing regulations and does not explain why the GPAC recommendation was rejected.

The Associations request that PHMSA reconsider this provision and consistent with the GPAC recommendation, amend the language modify the threshold for requiring immediate repair of a crack or crack-like anomaly to be 1.1 times MAOP after tool tolerance is verified using the *in situ* direct measurements in § 192.712(e)(1).[47]

C. The Associations request reconsideration of the requirement in § 192.478 to develop and implement a program to "monitor and mitigate" effects of corrosive "constituents" in a gas stream.

New § 192.478(a) requires that "[e]ach operator of an onshore gas transmission pipeline with corrosive constituents in the gas being transported must develop and implement a monitoring and mitigation program to mitigate the corrosive effects, as necessary."[48] Section 192.478(a) identifies carbon dioxide, hydrogen sulfide, sulfur, microbes and liquid water "either by itself or in combination" as "[p]otentially corrosive constituents," and requires that an operator "evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe, and implement mitigation measures as necessary."[49]

Section 192.478(b) describes the required elements of an internal corrosion monitoring and mitigation program, which includes the "use of gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents" and "[t]echnology to mitigate the potentially corrosive gas stream constituents." An operator also must perform an annual evaluation "to ensure that potentially corrosive gas

[44] *State Farm*, 463 U.S. at 43.
[45] 49 U.S.C. §§ 60102(b)(2), 60115(c)(2).
[46] *Pub. Citizen*, 374 F.3d at 1216 (finding that agency's failure to consider statutory factor constituted a failure to consider an important aspect of the problem).
[47] GPAC Meeting Final Voting Slides at 22 (March 26-28, 2018).
[48] Final Rule, 87 Fed. Reg. at 52,270 (to be codified at 49 C.F.R. § 192.478(a)).
[49] *Id.*

stream constituents" are monitored and mitigated effectively and annually review the program and implement adjustments as necessary based on program results.[50]

The Associations request that PHMSA reconsider the applicability of § 192.478(a) to transmission pipelines that transport gas containing "corrosive constituents." The regulation should instead apply to pipelines transporting "corrosive gas," consistent with existing long-standing regulations.[51] The Final Rule departs from the GPAC recommendation without providing the explanation required under the Pipeline Safety Act, is not based on evidence in the record, and does not reflect reasoned decision-making. The provision is impracticable and unreasonable. The Associations also petition for reconsideration of § 192.478(b) and requests that PHMSA clarify that operators will be permitted to develop and implement monitoring plans that are tailored to the operations of their individual systems

In the Notice of Proposed Rulemaking (NPRM), PHMSA proposed to require that an operator of an onshore gas transmission pipeline develop and implement a monitoring and mitigation program "to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects."[52] The proposal was the topic of extensive discussion at the January 11, 2017 and June 6, 2017 GPAC meetings.[53] GPAC members raised several points regarding the proposal, including that (1) data collected at isolated receipt points do not represent the composition of a commingled gas stream;[54] (2) operators use multiple methods to monitor a gas stream, such as sampling, information from suppliers, and reliance on tariff provisions, that do not require the monitoring gas at individual receipt points;[55] (3) the presence of corrosive constituents by themselves do not cause internal corrosion unless water is present and that this is the reason why pipelines have dewpoint requirements;[56] and (4) interstate natural gas pipelines have FERC Gas tariffs that establish gas quality specifications for the corrosive constituents identified in the proposed rule.[57] GPAC members requested that PHMSA provide data supporting the proposal and clarify the magnitude of the problem.[58]

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[50] *Id.*

[51] *See* 49 C.F.R. § 192.475(a) which prohibits an operator from transporting corrosive gas "unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion," and § 192.477 which requires that if corrosive gas is transported, an operator must use "coupons or other suitable means . . . to determine the effectiveness of the steps taken to minimize internal corrosion."

[52] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Notice of Proposed Rulemaking, 81 Fed. Reg. 20,722, 20,830 (Apr. 8, 2016) (proposed § 192.478(a)).

[53] GPAC Meeting Transcript at pp. 270-293 (January 11, 2017); GPAC Meeting Transcript at pp. 176-235 (June 6, 2017).

[54] GPAC Meeting Transcript at p. 279 (January 11, 2017) (Statement of Mr. Zamarin).

[55] GPAC Meeting Transcript at pp. 281-82; 291 (January 11, 2017) (Statements of Ms. Campbell and Ms. Fleck); GPAC Meeting Transcript at p. 220 (June 6, 2017) (Statement of Mr. Drake).

[56] GPAC Meeting Transcript at pp. 210-11 (June 6, 2017) (Statement of Mr. Zamarin).

[57] GPAC Meeting Transcript at p. 274 (January 11, 2017) (Statement of Ms. Campbell); GPAC Meeting Transcript at p. 188 (June 6, 2017) (Statement of Mr. Zamarin).

[58] GPAC Meeting Transcript at pp. 273, 278 (January 11, 2017) (Statements of Ms. Campbell and Mr. Zamarin).

The approved GPAC recommendation was that § 192.478(a) be modified to apply to gas transmission pipelines that transport "corrosive gas,"[59] not corrosive constituents. The reference to "corrosive gas" is consistent with other regulations addressing internal corrosion and, importantly, reflects the desire of PHMSA's Associate Administrator for Pipeline Safety to adopt language that is consistent with existing provisions already addressing internal corrosion.[60] For example, § 192.475 prohibits the transportation of corrosive gas unless the corrosive effect of the gas is investigated and minimized, and § 192.477 requires that an operator assess the effectiveness of measures taken to minimize internal corrosion.[61] Even the Final Rule's preamble states that new § 192.478(a) would apply to pipelines transporting "corrosive gas."[62]

The Final Rule rejects the GPAC's recommendation and instead of applying to transmission pipelines transporting corrosive gas, applies to transmission pipelines that transport gas "with corrosive constituents." The Final Rule does not address the issues raised by GPAC members and provides no explanation for rejecting the GPAC recommendation as required under the Pipeline Safety Act.[63]

Without addressing GPAC members' descriptions of how they already monitor and manage corrosive constituents in the gas, the Final Rule assumes that any gas stream containing corrosive constituents is a corrosive gas. This assumption is incorrect and does not account for the conditions that must exist for corrosive constituents to become harmful. For example, and as pointed out during the GPAC discussion, without liquid water, neither carbon dioxide nor hydrogen sulfide are corrosive.[64]

The Final Rule also does not account for the common practice of mixing gas streams on interstate natural gas pipelines. This practice enables operators to manage the gas transported in its pipelines and effectively mitigate potential harmful effects corrosive constituents. Interstate natural gas pipelines receive gas at various points throughout their pipeline systems, including from gathering systems, market hubs, and other transmission pipelines. The composition of the gas received into a pipeline system will vary (*e.g.*, volumes, pressures, and quantity of corrosive constituents). Any corrosive constituents that may be in a particular gas stream are mixed with other flowing gas on the pipeline to mitigate any harmful effects. Mixing corrosive constituents in the gas stream is a practice that is encouraged by the Federal Energy Regulatory Commission (FERC), the federal agency that regulates the interstate transportation of gas under the Natural Gas Act.[65] FERC policy encourages mixing gas streams because it maximizes the available of natural gas supplies to the market for the benefit of end-users and consumers across the country.

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[59] GPAC Meeting Final Voting Slides at pp. 32 (June 6-7, 2017). *See also* GPAC Meeting Transcript at pp. 199-200 (June 6, 2017) (Statement of Mr. Nanney) ("If corrosive gas is being transported," that's the key. We're not using non-dry gas, we were using "if corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion.").
[60] GPAC Meeting Transcript at pp. 223-24 (June 6, 2017) (Statement of Mr. Mayberry).
[61] 49 C.F.R. §§ 192.475(a), 192.477.
[62] Final Rule, 87 Fed. Reg. at 52,237-38, 52,258.
[63] 49 U.S.C. § 60115(c)(2).
[64] GPAC Meeting Transcript at pp. 210-11 (June 6, 2017) (Statement of Mr. Zamarin).
[65] 15 U.S.C. §§ 717-717z (2018).

The Final Rule does not acknowledge the fact that FERC is the federal agency with regulatory authority over the quality of the gas transported on interstate natural gas pipelines. Each interstate pipeline has a FERC-approved Gas Tariff that contains gas quality specifications.[66] A pipeline is required to accept gas that meets those gas quality specifications and requires permission from FERC to modify them. While these specifications vary from pipeline to pipeline depending on operating circumstances and market conditions, each FERC tariff contains a safe harbor for corrosive constituents, such as H_2S, CO_2 and water. This means that pipelines receive gas containing these constituents as a matter of course as part of normal operations. The Final Rule's requirement that an operator "evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe" and use "gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents,"[67] is at odds with the requirement that operators accept gas that fall within the safe harbors established in each interstate pipeline's FERC Gas Tariff.

The Final Rule's assumptions that transmission pipeline operator "have monitoring systems for the quality of the gas entering their systems" is not supported by the record.[68] This statement echoes PHMSA's statements during the GPAC meetings that operators monitor the gas coming onto their systems because "they're either paying or getting paid based on the quality of that gas."[69] This statement is incorrect. Operators measure the hydrocarbon content of gas, including methane, ethane, *etc.*, because those constituents contribute to the heating value of the gas, which when combined with the volume of gas, produces the number of dekatherms. Dekatherms are the value basis for payment for transporting gas.

Section 192.478(a) is based on unsupported assumptions about the risks associated with transporting gas containing corrosive constituents, and does not acknowledge pipelines' operating practices or other regulatory requirements that govern pipeline operations. PHMSA has not reconciled its assumptions about the effects of transporting gas containing corrosive constituents with the information provided by GPAC members and has not explained how the expansive scope of § 192.478(a) is supported by record evidence as required under the APA.[70] PHMSA also has not considered the appropriateness of the standard for the type of facility or the information received from the public and the GPAC, as required under the Pipeline Safety Act.[71]

Requiring an operator to implement a monitoring and mitigation program because the gas stream contains "corrosive constituents" is inconsistent with requirements in § 192.475 which addresses internal corrosion based on "corrosive gases." § 192.475(a) addresses control of corrosive gas by requiring that:

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[66] GPAC Meeting Transcript at p. 274 (January 11, 2017) (Statement of Ms. Campbell); GPAC Meeting Transcript at p. 188 (June 6, 2017) (Statement of Mr. Zamarin).
[67] Final Rule, 87 Fed. Reg. at 52,270.
[68] *Id.* at 52,238.
[69] GPAC Meeting Transcript at p. 192 (June 6, 2017) (Statement of Mr. Nanney); GPAC Meeting Transcript at p. 290 (January 11, 2017) (Statement of Mr. Nanney) (stating "I would be very surprised if H_2S, CO_2, all the issues for corrosive gas are not being monitored, because that also has to do with how much you pay on the cash register.").
[70] *State Farm*, 463 U.S. at 43, *Nat'l Fuel Gas Supply Corp.*, 468 F.3d at 839, 843 (vacating agency rule because record evidence did not support existence of the problem the rule purported to address).
[71] 49 U.S.C. § 60102(b).

> "Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been *investigated* and *steps have been taken to minimize* internal corrosion."[72]

The Final Rule also reflects a rejection of the agreed-upon GPAC recommendation that would limit proposed § 192.478 to onshore gas transmission pipelines that transport "corrosive gas."[73] The Final Rule does not explain why PHMSA departed from the GPAC recommendation as required under the Pipeline Safety Act.[74]

The Associations also petition for reconsideration of § 192.478(b) and requests that PHMSA clarify that operators will be permitted to develop and implement monitoring plans that are tailored to the operations of their individual systems. Monitoring plans will vary depending on a number of factors, including the geographic locations of receipt points and the source and volume of the gas coming in at these points (*i.e.*, a pooling point, a gathering pipeline, a storage facility, market hubs, pipeline interconnects) vs. the volume of gas transported in the mainline receiving the gas. Other relevant factors include the proximity of processing or treatment facilities, the volume of the receipt point, the potential impact of the receipt point on downstream facilities, and operational characteristics of the pipeline, such as operating pressure. Operators also need to have flexibility with respect to the types of monitoring methods they use, and if they use equipment, their locations.

D. The Associations request that PHMSA reconsider § 192.712(c)(9)'s requirement that operators assume a reassessment safety factor of 5 or greater when evaluating dents and other mechanical damage.

Existing § 192.712 describes how a transmission pipeline operator must determine the predicted failure pressure at the location of an anomaly or defect and the remaining life of a pipeline segment at the location of the anomaly or defect. PHMSA adopted this provision in the 2019 Gas Transmission Rule,[75] but left subsection 192.712(c) "reserved." In the Final Rule, PHMSA now adopts § 192.712(c), which addresses dents and other mechanical damage.[76]

Section 192.712(c)(9) states in relevant part:

> (c) *Dents and other mechanical damage.* To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows: . . . .(9) Using operational pressure data, a valid fatigue life prediction model that is appropriate for the pipeline segment, and <u>assuming a reassessment safety factor of 5 or greater for the assessment interval</u>, estimate the fatigue life of

[72] 49 C.F.R. § 192.475(a) (emphasis added).
[73] GPAC Meeting Transcript at pp. 176-77 (June 6, 2017) (Statement of Mr. Nanney); s*ee also* GPAC Meeting Final Voting Slides at 32 (June 6-7, 2017).
[74] 49 U.S.C. § 60115(c)(2).
[75] 84 Fed. Reg. at 52,205-06.
[76] Final Rule, 87 Fed. Reg. at 52,271.

the dent by Finite Element Analysis or other analytical technique that is technically appropriate for dent assessment and reassessment intervals in accordance with this section.[77]

The Associations request reconsideration of the requirement that operators assume a reassessment safety factor of 5 or greater for the assessment interval when evaluating dents and other mechanical damage. The record contains no basis for this language. It was not proposed in the NPRM or discussed by GPAC. In fact, it is inconsistent with language PHMSA itself proposed during the GPAC meeting. As a result, the GPAC did not discuss it or provide a recommendation on it. The Final Rule omits consideration of the safety benefit of the change in the safety factor. Section 192.712(c)(9) is not supported by substantial evidence and is arbitrary and capricious.[78]

The first mention of establishing reassessment factor occurred at the March 28, 2018 GPAC meeting. In response to comments previously received suggesting that PHMSA allow operators to use engineering critical assessments (ECA) to evaluate dents, PHMSA set forth a proposed approach. PHMSA's proposal was to "[e]stimate the fatigue life of the dent using [Finite Element Analysis (FEA)] with the operational pressure data and different fatigue life prediction models, which must have a reassessment *safety factor of 2*."[79] The transcript for the meetings on March 27 – 28, 2018 reflects that no GPAC member commented or objected to PHMSA's proposed approach.

The Final Rule's language requiring a safety factor of 5 is a significant departure from the proposed safety factor of 2 that PHMSA recommended at the March 27, 2018 GPAC meeting. PHMSA provides no explanation for adopting language that was not proposed in the NPRM, was not discussed by the GPAC and was not made available for public notice and comment. The impact of this change is to significantly increase the required frequency for performing a fatigue analysis and require reassessments of subject dents sooner without any discernable safety benefit justifying making an operator devote resources to non-critical safety tasks.

The Associations petition PHMSA to reconsider language in § 192.712(c)(9) adopting a safety factor of 5. PHMSA adopted this language without providing an opportunity for public notice and comment in violation of the APA.[80] The proposal is not the logical outgrowth of a proposal contained in the NPRM,[81] lacks record support, and does not reflect reasoned decision-making.[82] PHMSA's adoption of this language also is inconsistent with the rulemaking procedures of the Pipeline Safety Act because PHMSA has failed to consider relevant available gas pipeline safety information, the appropriateness of the standard for the type of transportation

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[77] *Id.* (underlining added for emphasis).
[78] *Owner-Operator Indep. Drivers Ass'n*, 656 F.3d at 588 (applying *State Farm* standard and vacating final rule as arbitrary and capricious).
[79] GPAC Meeting Slides at 149 (March 26-28, 2018) (emphasis added), *see also* GPAC Meeting Transcript at pp. 296-97 (March 27, 2018) (Statement of Mr. Nanney).
[80] *Owner-Operator Indep. Drivers Ass'n*, 656 F.3d at 588.
[81] *Nat'l Lifeline Ass'n v. FCC*, 921 F.3d 1102, 1116 (D.C. Cir 2019).
[82] *State Farm*, 463 U.S. at 52.

or facility, reasonableness, comments and information received from the public, and comments and recommendations of the GPAC.[83]

E. The Associations request that PHMSA reconsider §§ 192.714(d)(1)(iv) and 192.933(d)(1)(iv) to remove the requirement that operators treat metal loss affecting a longitudinal seam on a high-frequency electric resistance welded pipe as an immediate repair condition.

The Associations request reconsideration of the requirement in § 192.714(d)(1)(iv) and § 192.933(d)(1)(iv) that operators treat as an immediate repair condition metal loss "preferentially affecting a detected longitudinal seam, if that seam was formed by . . . high-frequency electric resistance welding . . . and the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP."[84] PHMSA has provided no data or analysis supporting this requirement and did not respond to concerns raised by INGAA and GPAC members during the GPAC meeting. These new regulatory requirements do not promote safety and are not practicable or reasonable.

This requirement originated in the NPRM's proposal to require that operators treat as an immediate condition, "[a]n indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high-frequency, electric resistance welding or by electric flash welding."[85]

In comments on the NPRM, INGAA explained that PHMSA had not explained or provided data supporting the proposal to treat metal loss associated with high-frequency electric resistance welded (HF-ERW) seams as an immediate repair condition.[86] INGAA pointed out that the proposal was inconsistent with Section 7.2.1 of B31.8S-2004 which does not treat HF-ERW seams as an immediate repair condition.[87] INGAA requested that PHMSA remove the proposal to treat as an immediate repair condition metal-loss affecting a detected longitudinal seam if the seam was formed by high-frequency electric resistance welding.

At the March 2, 2018 GPAC Meeting, PHMSA responded to comments on proposed § 192.933(d)(1)(v) that had requested PHMSA to (1) allow operators to perform fitness for service evaluations, and (2) clarify that the proposed regulation applies to selective seam weld corrosion rather than general corrosion crossing the seam weld.[88] PHMSA indicated that "[b]ased on incident investigation, experience, and data, it believes the proposed repair criteria is appropriate and inclusion of HF-ERW pipe seam welds in § 192.933(d)(1)(v) is appropriate."[89]

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[83] 49 U.S.C. § 60102(b)(2).
[84] Final Rule, 87 Fed. Reg. at 52,271-72, 52,277-78 (to be codified at 49 C.F.R. § 192.714(d)(1)(iv) and 192.933(d)(1)(iv)).
[85] 81 Fed. Reg. at 20,839 (proposed § 192.713(d)(1)(iv) and § 192.933(d)(1)(v)).
[86] Comments of INGAA on NPRM at 91-92 (July 7, 2016).
[87] *Id. See also* ASME/ANSI B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines," Sec. 7.2.1 (2004) (Incorporated by reference into Part 192. 49 C.F.R. § 192.7).
[88] GPAC Meeting Slides at 58 (March 2, 2018).
[89] GPAC Meeting Transcript at pp. 204-05 (March 2, 2018) (Statement of Mr. Nanney). GPAC Meeting Slides at 58 (March 2, 2018).

According to PHMSA, between 2010 and November 2017, ten pipe seam failures had occurred on high-frequency ERW pipe.[90]

At the March 2, 2018 GPAC meeting, INGAA recommended that metal loss affecting the long seam for HF-ERW pipe be removed as an immediate repair condition, noting that INGAA's analysis of data from 2010 to 2017 indicated that "there have been zero corrosion or environmental corrosion cracking, which are metal loss incidents affecting the long seam of high frequency ERW pipe."[91] A GPAC member requested more data regarding the cause of such failures before "declaring metal loss in high frequency seams a critical immediate anomaly."[92] Comments filed by the Associations after the March 2, 2018 GPAC meeting reiterated the recommendation that metal loss affecting a HF-ERW seam be removed as an immediate repair condition.[93]

At the March 27, 2018 GPAC meeting, PHMSA suggested "allowing, but not requiring, ECA analysis for the evaluation of corrosion metal loss affecting the long seam . . . . If the predicted failure pressure is less than 1.25 times the MAOP, the anomaly would be an immediate condition."[94] PHMSA also stated that it would add the word "preferentially to assure that this criterion would not be applied to small corrosion pits near long seam. It would only apply to corrosion along the seam that could lead to slotting-type crack-like defects."[95]

INGAA responded by reiterating that:

> [T]here's a criteria proposed to a requirement related to metal loss affecting the long seam. And we went back and looked at data from 2010 to 2017 and found zero corrosion or environmental corrosion metal loss incidents affecting the long seam of high frequency ERW pipes. Those pipes are not known to be particularly susceptible to this type of corrosion, so based on that incident review and our knowledge of this type of seam, we don't think high frequency ERW pipes should be included in the response and repair requirements related to metal loss preferentially affecting the long seam.[96]

The Final Rule adopts § 192.714(d)(1)(iv) and § 192.933(d)(1)(iv) with virtually no explanation. Without citing any supporting evidence or analysis, PHMSA asserts that HF-ERW pipe is among the seam types "known to be susceptible to latent manufacturing defects."[97] PHMSA does not address the comments of INGAA and other operators that pointed out that

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[90] GPAC Meeting Slides at 59 (March 2, 2018).
[91] GPAC Meeting Transcript at p. 242 (March 2, 2018) (Statement of Mr. Osman).
[92] *Id.* at pp. 258-59 (Statement of Mr. Drake).
[93] Comments on PHMSA Gas Pipeline Advisory Committee (GPAC) Teleconference Held March 2, 2018 filed by the American Gas Association, API, American Public Gas Association and INGAA at 12 (Mar. 9, 2018).
[94] GPAC Meeting Transcript at p. 308 (March 27, 2018) (Statement of Mr. McLaren). *See also* GPAC Meeting Transcript at p. 20 (March 28, 2018) (Statement of Mr. McLaren), GPAC Meeting Slides at 167 (March 26-28, 2018).
[95] GPAC Meeting Transcript at p. 309 (March 27, 2018) (Statement of Mr. McLaren) (stating "PHMSA suggests inserting the word preferentially to assure that this criterion would not be applied to small corrosion pits near a long seam. It would only apply to corrosion along the seam that could lead to slotting-type, crack-like defects.").
[96] GPAC Meeting Transcript at pp. 127-28 (March 28, 2018) (Statement of Mr. Osman).
[97] Final Rule, 87 Fed. Reg. at 52,261 & n.53.

PHMSA has not demonstrated that such pipe *is* susceptible to corrosion in the long seam and does not explain its analysis of the incident data cited during the GPAC meeting. PHMSA also does not account for the costs and benefits of this provision in its Final Regulatory Impact Statement in violation of the Pipeline Safety Act.[98]

Not only are PHMSA's assertions regarding HF-ERW pipe unsupported and inaccurate, but they have practical implications for operators who will be required to prioritize and direct resources to pipe with HF-ERW seams, when those resources may be more effectively directed to pipe that poses much higher risk.

The Final Rule is inconsistent with record evidence and does not reflect reasoned decision making.[99] PHMSA has failed to reveal the technical basis for this provision.[100] Requiring that operators treat metal loss affecting a longitudinal seam on HF-ERW as an immediate repair condition is not practicable or reasonable and the Associations request that PHMSA revise § 192.714(d)(1)(iv) and § 192.933(d)(1)(iv) to remove the reference to high-frequency electric resistance welded pipe.

F. The Associations request PHMSA to reconsider and amend § 192.473(c)(4) to allow an operator to notify PHMSA of the need for additional time under § 192.18 if the operator is unable to complete remedial actions to address stray currents within 15 months of completing an interference survey.

Under § 192.473, an operator whose pipeline is subject to stray currents must have a continuing monitoring plan to minimize the detrimental effects of such currents.[101] The Final Rule amends § 192.473 to require that an operator's continuing program provide for performing interference surveys, analyzing the results of the survey, developing a remedial action plan to correct certain types of interference currents, and applying for any necessary permits within 6 months of completing the survey that identified the deficiency.[102] Section 192.473(c)(4) requires that an operator "complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency, or as soon as practicable, but not to exceed 6 months after obtaining any necessary permits."[103]

The Associations request reconsideration of § 192.473(c)(4)'s requirement to complete stray current remedial actions within 15 months after completing the interference survey. Because of the nature of stray currents and the length of time over which their potential detrimental effects are observed and measured, an operator may not have the ability to complete

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[98] 49 U.S.C. § 60102(b)(2).
[99] *Nat'l Fuel Gas Supply*, 468 F.3d at 839, 843 (vacating agency rule because record evidence did not support existence of the problem the rule purported to address).
[100] *Owner-Operator Indep. Drivers Ass'n*, 494 F.3d at 199 (citing *Solite Corp. v. EPA*, 952 F.2d 473, 484 (D.C. Cir. 1991)) (finding that agency's failure to disclose the methodology of the agency's operator-fatigue model for performing a crash-risk analysis when that model was the basis for the cost-benefit analysis used in the agency's Regulatory Impact Assessment violated APA's notice and comment requirements).
[101] 49 C.F.R. § 192.473.
[102] Final Rule, 87 Fed. Reg. at 52,273 (to be codified at § 192.473).
[103] *Id.* at 52,269-70 (to be codified at § 192.473(c)(4)).

remedial actions within 15 months. In addition, mitigation can be an iterative process. An operator can measure and evaluate interference levels and install mitigation and yet not achieve anticipated mitigation. This requires additional measurement and evaluation to determine a modified interference mitigation design requiring more analysis and additional time.

Interference can result from proximity to other pipelines, sources of alternating current interference such as high voltage power lines, and direct current such as rail transportation. In mitigating interference where the sources of interference are known an operator will develop a design to address the interference. The operator will install and operate mitigation technology as the pipe is installed and evaluate interference as cathodic protection is installed in the year that follows completion of construction.[104] As the pipeline is placed into operation and the cathodic protection system is balanced, the operator will monitor interference levels. This can entail developing monitoring plans to evaluate when interference levels change as well as peak.

One of the challenges an operator can face is getting data from a power transmission or rail operator on the nature of the interference and so it takes time for the operator to collect and evaluate data. Monitoring can require data collection over a full year to understand the range of interference levels. For example, interference can be seasonal, intra-day, etc, which has the effect of requiring more than 15 months to mitigate. Consequently, the 15-month time frame for remediating interference currents may not be practicable.

The Associations request that PHMSA amend the regulation to require that an operator complete remedial actions within 15 months of performing the interference survey, subject to the ability to notify PHMSA of the need for and the duration of a time extension under § 192.18. This amendment would recognize that addressing the effects of stray currents can occur over a time period that exceeds 15 months.

G. The Associations request that PHMSA clarify that the language in § 192.710(a)(2) and § 192.624(a)(2)(iii) referring to pipeline segments that "can accommodate inspection by means of an instrumented inline inspection tool" refers to free-swimming tools, *i.e.*, tools that do not require facility modification.

The Associations request that PHMSA clarify how the new definition of "in-line inspection (ILI)" will be applied under § 192.624(a)(2)(iii) and § 192.710(a)(2) with respect to pipeline segments located in moderate consequence areas (MCA) that can accommodate an ILI. Specifically, the Associations request that PHMSA clarify that the term "instrumented inline inspection tool" refers to free-swimming tools, *i.e.*, tools that do not require permanent modification to the pipeline facility.

The NPRM proposed to define the term "in-line inspection" as "the inspection of a pipeline from the interior of the pipe using an in-line inspection tool, which is also called *intelligent* or *smart pigging*."[105] During the March 27, 2018 GPAC meeting, PHMSA and the GPAC agreed to further clarify the proposed definition by adding the following sentence stating

[104] 49 C.F.R. § 192.455(a)(2).

[105] 81 Fed. Reg. 20,722 at 20,805 (emphasis added).

"[t]his definition includes tethered and self-propelled inspection tools."[106] Several GPAC members expressed concern that existing language in § 192.710 and § 192.624 that refers to pipelines located in MCAs that can accommodate ILIs could be interpreted to require that an operator make permanent facility modifications to accommodate ILI tools.[107]

To address this concern, PHMSA agreed to include language in the Final Rule's preamble that clarifies that the applicability language in § 192.710 and § 192.624 is limited to pipeline segments that can accommodate free-swimming ILIs, *i.e.*, tools that can be deployed without the pipeline having to be modified to accommodate an ILI.[108] The voting slides for the March 27, 2018 GPAC meeting reflect that PHMSA would "[c]onsider adding 'free-swimming' to the definition for 'pipe segment can accommodate inspection by means of an instrumented in-line inspection tool.'"[109]

In the Final Rule, PHMSA adopted a definition of "in-line inspection" that is based on definitions in NACE SP0102-2010, including the sentence stating that the definition "includes tethered and self-propelled inspection tools."[110] While the Final Rule states that "an ILI can include both tethered and self-propelled (*i.e.*, 'free-swimming') tools,"[111] the preamble does not clarify that the applicability language in § 192.710 and § 192.624 is limited to pipeline segments that can accommodate free-swimming ILIs, *i.e.*, tools that do not require modification to accommodate an ILI.

The Associations support the new definition of ILI, but requests that PHMSA adopt an FAQ making clear that the new definition is not to be interpreted to require that operators use ILI tools that require permanent modifications to pipeline facilities, thereby expanding the applicability of § 192.710 and § 192.624. Section 192.710 sets forth requirements for assessments outside of HCAs. Section 192.624 addresses reconfirming MAOP for onshore steel transmission lines. Both sections, which were adopted in the 2019 Gas Transmission Rule,[112] apply to pipeline segments located in MCAs "if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool."[113] Addressing the meaning of "piggable" in the preamble for that final rule, PHMSA recounted that during the GPAC meetings it had noted that a "piggable line" would be one without physical or operational modifications.[114]

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[106] GPAC Meeting Slides at 126 (March 26-28, 2018).
[107] GPAC Meeting Transcript at pp. 209-215 (March 27, 2018).
[108] GPAC Meeting Transcript at pp. 198, 205 (March 27, 2018) (Statement of Mr. McLaren).
[109] GPAC Meeting Final Voting Slides at 13 (March 26-28, 2018).
[110] Final Rule, 87 Fed. Reg. at 52,267 (to be codified at 49 C.F.R. § 192.3).
[111] *Id.* at 52,256.
[112] 84 Fed. Reg. 52,180.
[113] 49 C.F.R. §§ 192.624 and 192.710.
[114] 2019 Gas Transmission Rule, 84 Fed. Reg. at 52,227 ("[t]he GPAC, based on a comment made by a member of the public, asked if PHMSA could provide more guidance on what a 'piggable' line is, for the purposes of the [MCA] definition. The GPAC asked whether PHMSA believed that qualifier applies to pipelines that can be fully assessed by a traditional, free-swimming ILI tool without further modification to the pipeline, and PHMSA noted during the meeting that a 'piggable' line would be one without physical or operational modifications.") The 2019 Gas Transmission Rule also stated that a line is piggable "if it can accommodate an instrumented ILI tool without the need for major physical or operational modification, other than the normal operational work required by the process of performing the inline inspection." *Id.* at 52,215.

The Associations' requested clarification is important to ensure that the term "instrumented inline inspection tool" in § 192.710 and § 192.624 refers to free-swimming tools, *i.e.*, tools that can be deployed without requiring permanent modification to the pipeline facility. Without this clarification, pipeline operators would face the risk that § 192.710 and § 192.624 may be interpreted to require that an operator physically modify a pipeline facility to accommodate ILI tools. The result would be to require an operator to modify currently unpiggable lines to make them piggable, thereby increasing the amount of pipeline mileage subject to § 192.710 and § 192.624. Such an outcome would not be practicable or reasonable and was not contemplated during the rulemaking process or analyzed in PHMSA's Final Regulatory Impact Analysis. Such an outcome also would be contrary to the GPAC expectations without providing any reason for rejecting GPAC's conclusion.[115]

H. The Associations request reconsideration of § 192.714(b) to allow operators to use values for Charpy v-notch toughness consistent with § 192.712(d)(3).

Section 192.714 sets forth the repair criteria for onshore transmission pipelines not located in an HCA. Section 192.714(b) states the following:

> A pipeline segment's operating pressure must be less than the predicted failure pressure determined in accordance with § 192.712 during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, and operator must obtain the undocumented data through § 192.607.[116]

This language requires that (1) if a given anomaly is predicted to have a very low failure pressure using the excessively conservative process as defined in § 192.712, an operator would have to reduce the pressure to the calculated failure pressure, even if the anomaly is not an imminent risk as demonstrated by the fact that the anomaly has not failed at normal operating pressure, and (2) if traceable, verifiable and complete records documenting data that is required to perform a predicted failure pressure analysis is not available, the operator must obtain the undocumented data using the material verification process in § 192.607.

This language, however, is not consistent with language in § 192.712 which allows an operator to use existing toughness data. Specifically, § 192.712 describes how a transmission pipeline operator is required to determine the predicted failure pressure at the location of an anomaly or defect and the remaining life of a pipeline segment at the location of the anomaly or defect. Section 192.712(d), which was adopted in the 2019 Gas Transmission Rule,[117] addresses cracks and crack-like defects. More specifically, § 192.712(d)(3) provides in part that:

> If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch

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[115] 49 U.S.C.§ 60115(c)(2).
[116] Final Rule, 87 Fed. Reg. at 52,271.
[117] 84 Fed. Reg. at 52,271.

> toughness values based upon minimum operational temperature and equivalent to a full-size specimen value: (i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer . . . (iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with § 192.18.[118]

Charpy v-notch toughness values were discussed extensively at the GPAC meetings that led to the Final Rule and to the 2019 Gas Transmission Rule. The language codified in § 192.712(d)(3) allowing the use of values from comparable pipe or other values an operator can demonstrate provide a conservative Charpy v-notch toughness value reflects the outcome of those GPAC discussions and the GPAC recommendation.

Allowing an operator the flexibility to use comparable or other appropriate values is important from a practical perspective because no technology exists to measure toughness, including Charpy toughness, through non-destructive evaluation (NDE) (*i.e.*, testing) in an excavation. The only way to determine toughness is to cut out the pipe and test it in a laboratory or use comparable values like those permitted in § 192.712(d)(3). Having to perform a test in order to complete a repair for an excavated pipe is not practicable or reasonable. It does not promote safety when comparable data provides reasonable and safe Charpy toughness values. Furthermore, the requirement to reduce pressure during repairs based on the predicted failure pressures calculated using § 192.712 constitutes an unreasonable burden since the low calculated failure pressures are principally a result of the very conservative requirements in § 192.712 and do not reflect the true failure pressure of the anomaly.

The Associations request reconsideration of § 192.714(b) to permit an operator to apply the same process for determining Charpy v-notch toughness values as permitted under § 192.712(d)(3). PHMSA has not identified any basis for having two different processes for determining the predicted failure pressure of an anomaly or defect. Rather, the Associations believe that its request is consistent with PHMSA's intention of establishing consistent approaches in the two regulations. The Associations request that the language of § 192.714(b) be amended as follows:

> A pipeline segment's operating pressure must be reduced to a safe pressure established using sound engineering principles during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, and operator must <u>follow the procedures set forth in § 192.712(d)(3)</u>~~obtain the undocumented data through § 192.607~~.

In addition, the Associations request clarification on use of toughness values. While the § 192.712 often refers to Charpy toughness, the language related to the general requirements of

[118] 49 C.F.R. § 192.712(d)(3).

§ 192.712 describes the use of crack assessment models, including use of proven fracture mechanics models as below:

> When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).[119]

Many of the proven fracture mechanics models as required by the code, use material fracture toughness (not Charpy V-notch impact energy) as an input. This is because fracture toughness testing results better reflect the quasi-static (slow progressing) crack propagation behavior in pipeline steels than the Charpy V-notch method, which is a dynamic load test and measures the impact energy a material can absorb. If Charpy are the only data available, an operator must use a correlation that relates Charpy to another metallurgical toughness measures.

The Associations request that PHMSA clarify that other methods of toughness used in proven fracture mechanics models can be used within the modeling framework established in § 192.712(d)(1). This will include fracture toughness testing methods such as ASTM E1820 or BS 8571, *i.e.*, measures of toughness as specified by many of the proven models.

In addition, when PHMSA promulgated 2019 Gas Transmission Final Rule, and § 192.712(e)(2)(D) that established default Charpy toughness values for segments with a history of reportable incidents caused by cracking or crack-like defects, the Associations were unaware that PHMSA would not adopt the GPAC's unanimous recommendation to adopt 1.1 x MAOP including after tool tolerance has been field verified and applied.[120] Furthermore, pipeline operators did not have the data necessary to evaluate the impact of these default values as crack ILI tools were not as broadly used. The bases for these toughness default values was unclear, but the Associations had no reason to believe that PHMSA would reject the GPAC recommendation. With PHMSA's departure from the GPAC recommendation, the default values contained in § 192.712(e)(2)(D), in combination with a more conservative repair criterion, have the effect of adding multiple layers of conservatism without providing any supporting evidence or analysis, without explaining the risk to be addressed, or identifying a commensurate safety benefit. Furthermore, the Associations believe that, when considered in its totality, the excessive conservatism discourages innovation and advancement of technology.

The Associations request reconsideration of the Charpy v-notch default toughness values established in § 192.712(e)(2)(D) for segments with a history of reportable incidents caused by cracking or crack-like defects.

Finally, § 192.714(b), requires that during repairs, an operator must reduce the operating pressure to less than the predicted failure pressure determined in accordance with § 192.712. The multiple layers of conservatism discussed above in some instances could result in pressure

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[119] *Id*. § 192.712(d)(1).
[120] *See* Section IV.B above.

reductions well below a safe operating limit. The Associations request that the provision be modified to use language provided for temporary pressure reductions in § 192.714(e)(i):

> A pipeline segment's operating pressure must be reduced during the repair process to a level not exceeding 80 percent of the operating pressure at the time condition was discovered or a level not exceeding the predicted failure pressure as calculated using § 192.712.[121]

This would a margin of safety comparable to pressure reductions for other repairs and is consistent with language in § 192.714(e)(i).

I. The Associations request reconsideration of § 192.319(f) to clarify that the deadline for an operator to repair severe coating damage is six months after having performed an assessment or within six months after receiving any necessary permits.

Section 192.319(d) requires that,

> [P]romptly after a ditch for an onshore steel transmission line is backfilled (if the construction project involves 1,000 feet or more of continuous backfill length along the pipeline), but not later than 6 months after placing the pipeline in service, the operator must perform an assessment to assess any coating damage and ensure integrity of the pipeline coating.[122]

Section 192.319(f), in turn, requires that an operator repair any severe coating damage "within 6 months after the pipeline is placed in service, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after receipt of the permits."[123]

The Associations request reconsideration of § 192.319(f) because it will require that an operator repair severe coating damage within six months after placing the pipeline into service. Such a compressed compliance timeframe does not provide an operator adequate time to both perform the coating assessment and then perform repairs. As currently drafted, § 192.319(d) and § 192.319(f) describe actions that are to be performed consecutively but then requires the second action to be taken within the same compliance deadline as the first. INGAA believes that this is a drafting error in the regulation and requests that PHMSA revise § 192.319(f) to permit an operator to complete any coating repairs within six months of having performed the assessment or within six months after receiving any necessary permits.

The Associations' request is consistent with § 192.461(f) and § 192.461(h) which address assessments that are performed after repairing or replacing an onshore steel pipeline that resulted in 1000 or more feet of backfill length along the pipeline. Section 192.461(f) requires that, within six months after the backfill, an operator must perform an assessment to assess any coating damage and ensure integrity of the coating. Within six months of completing any

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[121] 87 Fed. Reg. at 52,273.
[122] *Id.* at 52,268-69 (to be codified at § 192.319(d)).
[123] *Id.* at 52,268-69 (to be codified at § 192.319(f)).

assessment that identifies a deficiency, the operator must develop a remedial action plan and apply for permits needed to perform the repair. The operator must repair any severe coating damage within six months of performing the assessment, or as soon as practicable after obtaining necessary permits, but within six months of receiving the permits.

In addition, the Associations' request is consistent with PHMSA's statements at the June 6, 2017 GPAC meeting where PHMSA stated its intent for both § 192.319 and § 192.461 to "link" "the assessment timeframe to six months after the pipeline is placed in service, . . . plus an additional six months to complete the repairs"[124]

J. The Associations request that PHMSA grant reconsideration of 192.917(b) with respect to the meaning of "pertinent" and the requirement to collect data that has minimal, if any impact on safety.

The Final Rule amends existing § 192.917(b) to require that an operator gather and evaluate the data listed in § 192.917(b)(1). The regulation requires that the evaluation "analyze both the covered segment and similar non-covered segments, and it must (1) Integrate pertinent information about pipeline attributes to ensure safe operation and pipeline integrity, including information derived from" required operations and maintenance activities.[125] The regulation requires that an operator "begin to integrate all pertinent data elements specified in this section starting on May 24, 2023, with all available attributes integrated by February 26, 2024."[126]

The Associations request reconsideration with respect to the term "pertinent." Not all data will be pertinent for all pipelines in managing threats and risk. In addition, there can be other data that provide comparable information, and in some cases, eliminate a threat. For example, discharge temperature is relevant to coating and ultimately external corrosion, but when an operator can demonstrate temperatures will not adversely affect the coating, temperature data on downstream segments are unnecessary. The Associations request that operators be permitted to define the term when managing threats on their systems because the pertinence of data will vary from pipeline to pipeline based on a number of factors affecting individual facilities.

K. The Associations request reconsideration of § 192.714 to allow for a critical strain analysis of monitored dents.

New section 192.714 establishes repair criteria for onshore transmission pipelines that are not subject to integrity management regulations.[127] Section 192.714(d)(3) describes conditions that operators must record and monitor, but are not required to schedule for remediation. Among the monitored conditions is "A dent that is located between the 4 o'clock and 8 o'clock positions (bottom $^{1}/_{3}$ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12)."[128]

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124 Transcript of GPAC Meeting at p. 39 (March 6, 2017) (Statement of Mr. Nanney).
125 Final Rule, 87 Fed. Reg. at 52,273 (to be codified at § 192.917(b)).
126 *Id.*
127 *Id.* at 52,271.
128 *Id.* at 52,272 (to be codified at § 192.714(d)(3)(i)).

PHMSA's amended integrity management regulations contain monitored conditions that are similar, if not the same, as those listed in § 192.714(d). In particular, § 192.933(d)(3)(i) identifies the following as a monitored condition:

> A dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS12), located between the 4 o'clock and 8 o'clock positions (bottom $^{1}/_{3}$ of the pipe), and *for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded*.[129]

These monitored conditions are the nearly the same, except that § 192.714(d)(3)(i) does not contain the italicized language providing that an engineering analysis demonstrates that critical strain levels are not exceeded.

The Associations request that PHMSA reconsider § 192.714(d)(3)(i) to correct the inconsistency and to add the following language, which mirrors § 192.933(d)(e)(i): and *for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded*. There is no basis for allowing a critical strain analysis for this condition if found on a pipeline subject to integrity management regulations, but not allow the analysis for a pipeline not subject to integrity management.

L. The Associations request reconsideration of § 192.929(b)(3) to clarify the number of examination digs are required when performing direct assessment for stress corrosion cracking.

Section 192.929 sets forth the requirements applicable to an operator's plan for conducting direct assessment for the threat of stress corrosion cracking (SCC). The NPRM proposed to substantially revise this provision, including the addition of § 192.929(b)(3) addressing direct assessments. Proposed § 192.929(b) stated, "(3) *Direct examination.* In addition to the requirements and recommendations of NACE SP0204-2008, the plan's procedures for direct examination must provide for conducting a minimum of three direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur."[130]

The Associations supported this provision and it was not addressed during the GPAC meetings.

The Final Rule, however, modified the language of § 192.929. Instead of requiring an operator to conduct "a minimum of three direct examinations within the SCC segment," the Final Rule requires that an operator conduct "a minimum of three direct examinations for SCC within the covered pipeline segment."[131]

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[129] *Id.* at 52,278 (to be codified at § 192.933(d)(3)(i)) (emphasis added).
[130] 81 Fed. Reg. at 20,722, at 20,845.
[131] Final Rule 84 at 52,276/

This modification is potentially significant. In a valve section, an operator may have three covered segments that the operator considers to be one SCC segment. The NPRM would have required that an operator perform three excavations in that SCC segment. By changing "SCC segment" to "covered pipeline segment, however, the Final Rule could be interpreted to require that an operator perform three excavations in each covered segment, *i.e.* nine excavations in the SCC segment.

The modification to the Final Rule language was not subject to notice and comment as required under the APA[132] and was not discussed by the GPAC. Nor are the costs of this provision reflected in PHMSA's Regulatory Impact Analysis, which concludes that the incremental costs related to integrity management are zero, as required under the Pipeline Safety Act.[133] The Associations request that PHMSA amend the Final Rule to re-instate the language as proposed in the NPRM.

In addition, the Associations request that PHMSA reconsider § 192.929(b)(2) which states:

> (2) *Indirect inspection*. In addition to NACE SP0204, the plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using the complementary measurement tools most appropriate for the pipeline segment based on an evaluation of integrated data.

The Associations request that PHMSA grant reconsideration of this language that so that it better aligns with the requirements of NACE SP0204-2008. Specifically, the Associations request that PHMSA clarify that an operator may use indirect inspection, or other types of measurements, such as ILI, that appear to be precluded under the existing text requiring two above-ground surveys. An ILI, which is permitted under NACE SP0204-2008, can provide comparable data and PHMSA should permit an ILI to replace one of the two above ground surveys.

M. Clarifications and Technical Corrections

The Associations request that PHMSA make the following clarifications and technical corrections to the Final Rule. The Associations may identify additional issues that may require clarification.

1. The Associations request that § 192.714 be revised to include a reference to section 7 of ASME/ANSI B31.8S-2004.

Section 192.714(d)(1), which addresses immediate repair conditions for non-HCA pipelines, does not contain the reference to section 7 of ASME B31.8S-2004 that is contained in the corresponding integrity management provision, § 192.933(d)(1). This is important because section 7 of ASME/ANSI B31.8S-2004, which is incorporated by reference into the regulations, contains important requirements that apply to the remediation of immediate repair conditions,

[132] *Owner-Operator Indep. Drivers Ass'n*, 656 F.3d at 588.
[133] 49 U.S.C. § 60102(b)(2).

including a provision allowing an operator five days following the determination of the existence of the condition in which to perform an examination. This is especially important because pipelines located outside of HCAs are subject to § 192.710 which addresses assessments outside of HCAs.

The Associations request that PHMSA add the following language to § 192.714(d)(1): "An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S-2004, section 7 in providing for immediate repair conditions."

2. The Associations request that PHMSA amend the definition of "wrinkle bend" to correct the formula.

The Final Rule adopted a definition for "wrinkle bend," adopting the definition as proposed in the NPRM. The Associations have determined that the formula reflected in the regulations is missing content and requests that the definition be revised to correct the listed equations.

3. The Associations request that PHMSA clarify reference to "uprate" in 192.714(d)(2)(v) and 192.933(d)(2)(c).

Sections 192.714(d)(2) and § 192.933(d)(2) describe several conditions as two-year conditions and one-year conditions, respectively. Several of the descriptions contains the following phrase: "the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611."[134]

Section 192.611 does not govern uprating a pipeline. The Associations request that PHMSA amend these sections to make clear that a class location, not MAOP, was uprated in accordance with § 192.611.

4. The Associations request clarification of the definition of "Systemic" and "Non-systemic" in § 192.465(f).

Under § 192.465(f), if any annual test station reading indicates cathodic protection levels below required levels, the operator must determine the extent of the area that is inadequately protected. Under § 192.465(f)(1), an operator "must investigate and mitigate any non-systemic or location-specific causes."[135] If the cause of cathodic protection levels is systemic, the operator must perform close interval surveys in both directions from the test station that is producing the low reading. An operator must remediate areas with insufficient cathodic protection and confirm that adequate cathodic protection has been restored. If the cause is non-systemic, such as a blown fuse in a cathodic protection rectifier, when the fuse is replaced and the rectifier settings confirmed, the work is complete. The operator need not conduct close interval surveys in both directions from the rectifier.

[134] Final Rule, 87 Fed. Reg. at 52,272, 52,278.
[135] *Id*. at 52,269.

The Associations request that PHMSA provide regulatory compliance guidance with respect with respect to meaning of the terms "systemic" and "non-systemic," as these terms are not discussed in the Final Rule.

5. The Associations request that PHMSA clarify that "100amps/m^2" should be "100 amps/m^2 AC" in § 192.473(c)(3).

Section 192.473(c)(3) requires that an operator whose pipeline is subject to stray currents must have a continuing monitoring plan to minimize the detrimental effects of such currents.[136] The final rule specifies the requirements of such programs. Section 192.473(c)(3) requires the development of a remedial action plan to correct instances where interference current, among other things, is greater than or equal to 100 amps per meter squared (100 amps/m^2).

The Associations believe that the reference to "100 amps/m^2" is a typographical error and requests that PHMSA amend the regulation so that it states "100 amps/m^2 AC."

6. The Associations request that PHMSA clarify the meaning of growth prior to the next scheduled assessment in § 192.933(d)(3).

In the NPRM, PHMSA proposed § 192.933(d)(1)(vi) to include as an immediate repair condition "[a]ny indication of significant stress corrosion cracking (SCC)."[137] In its comments on the NPRM, INGAA requested that PHMSA delete this provision and instead reference the 1.1xMAOP failure pressure ratio for determining whether crack anomalies are an immediate repair condition. During the GPAC meeting, PHMSA proposed the following cracking repair criteria for HCA (1-year condition) and non-HCA (2-year condition) pipe: "The crack anomaly is determined to have (or will have prior to the next assessment) a predicted failure pressure (PFP that is less than 1.39 times MAOP (for Class 1) or 1.50 time MAOP (for Classes 2, 3and 4)."[138] Following discussion, the GPAC recommended several modifications to the proposed language, including removal of the "or will have prior to the next assessment" language.[139]

In the Final Rule, PHMSA removed this language from what became § 192.33(d)(2)iv), but added the following language to § 192.933(d)(3) addressing "monitored conditions."

> Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but if an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition:[140]

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[136] 49 C.F.R. § 192.473.
[137] 81 Fed. Reg. at 20,846.
[138] GPAC Meeting Slides at 188 (March 26-28, 2018).
[139] GPAC Meeting Final Voting Slides at 22 (March 26-28, 2018).
[140] Final Rule, 87 Fed. Reg. at 52,278.

The Associations request that PHMSA clarify what actions are required if an anomaly is expected to "grow to dimensions" or "have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment."

V. Conclusion

As set forth herein, the Associations request that PHMSA grant the petition for reconsideration of several provisions of the Final Rule.

Respectfully submitted,

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September 23, 2022

U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
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RE: Response to Petition of Reconsideration of the Interstate Natural Gas Association of America and the American Petroleum Institute, Docket No. PHMSA-2011-0023

Dear Messrs. Kochman and Murk:

This letter is a response to the September 23, 2022, Petition for Reconsideration (the "Petition") of the final rule titled "Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments"[1] you submitted on behalf of the Interstate Natural Gas Association of America ("INGAA") and the American Petroleum Institute ("API") (collectively "Petitioners"). For the reasons described below, PHMSA grants Petitioners' requests with respect to requests on which PHMSA acknowledges the value in temporary relief to facilitate timely implementation of the Final Rule, technical correction, or clarification in forthcoming guidance,[2] and denies Petitioners' requests for reconsideration of certain other elements of the Final Rule while providing clarification on these points.

[1] 87 FR 52224 (Aug. 24, 2022) ("Final Rule").
[2] PHMSA intends to publish such guidance initially in draft form to provide Petitioners and other stakeholders an opportunity to engage PHMSA on that guidance's contents. PHMSA further notes that, in developing that draft guidance, it will consider materials submitted by Petitioners in conversations with PHMSA following submission of their Petition. Additionally, a docket entry reflecting conversations with Petitioners in conjunction with their Petition will be uploaded shortly to the docket of this rulemaking, Docket No. PHMSA-2011-0023.

A. PHMSA will exercise enforcement discretion to provide operators additional time to comply with certain regulatory requirements in the Final Rule.

The compliance date for most of the provisions of the Final Rule is the Final Rule's effective date of May 24, 2023, nine months after the publication of the Final Rule. INGAA and API request an extension of the effective date to 18 months after publication in the *Federal Register* (extending the effective date of the Final Rule from May 24, 2023, until February 24, 2024) for all provisions of the Final Rule to facilitate operators' timely compliance with the requirements of the Final Rule (as elaborated by forthcoming guidance) and other recent PHMSA rulemakings.[3] Petition at 5-7.

PHMSA grants this request in part. PHMSA acknowledges the efforts by operators (supported by their trade associations) to comply with regulatory requirements introduced in the Final Rule, any forthcoming guidance issued by PHMSA, and other recently issued PHMSA rulemakings. PHMSA also acknowledges that timely implementation of multiple new regulatory requirements can require additional lead time to estimate and deploy sufficient resources, adding an additional challenge for some operators in their efforts to achieve compliance. PHMSA, therefore, will exercise enforcement discretion for nine months beyond the effective date (from May 24, 2023, until February 24, 2024) for most requirements in the Final Rule. For pipelines in service as of the publication date of the Final Rule (i.e., August 24, 2022), PHMSA has announced its exercise of inherent enforcement discretion not to enforce most provisions of the Final Rule except those provisions that were provided in the Final Rule with independent compliance timelines (i.e., 49 CFR 192.917(b) and 192.13(d)).[4] For pipelines entered into service (including new and replaced lines) after the publication date (i.e., between August 24, 2022, and the February 24, 2024, expiration of such discretion), PHMSA has now also announced in a notice posted to its public website that it will exercise enforcement discretion not to enforce most provisions of the Final Rule until February 24, 2024, except for: (1) §§ 192.917(b) and 192.13(d) as noted above, and (2) the corrosion control and extreme weather provisions found in §§ 192.319, 192.461, and 192.613.[5] PHMSA understands that such targeted enforcement discretions would, among other things, focus operators' resources on careful, comprehensive implementation of the Final Rule's requirements, including with benefit of the implementation guidance PHMSA plans to issue, while ensuring critical corrosion control requirements are incorporated on forthcoming construction or repairs, and extreme weather events continue to be accounted for.

B. PHMSA declines to modify the Final Rule's repair criteria for immediate repair of cracks causing a predicted failure pressure less than 1.25 times MAOP but will issue guidance underscoring an operator's responsibility upon discovery of an immediate

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[3] Specifically, Petitioners refer to the rule titled "Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards," 87 FR 20940 (Apr. 8, 2022).

[4] https://www.phmsa.dot.gov/regulatory-compliance/phmsa-guidance/notice-limited-enforcement-discretion-existing-onshore-gas.

[5] https://www.phmsa.dot.gov/news/notice-limited-enforcement-discretion-new-and-replaced-onshore-gas-transmission-pipelines.

repair condition, including appropriate temporary pressure reductions to prioritize repair.

Petitioners criticize as unsupported in the administrative record the Final Rule's crack repair criteria in §§ 192.714(d)(1)(v)(C) and 192.933(d)(1)(v)(C) obliging gas transmission pipeline operators to immediately repair cracks (or crack-like anomalies) causing predicted failure pressure ("PFP") less than 1.25 times the Maximum Allowable Operating Pressure ("MAOP") of the pipeline segment. Petition at 7-10. Petitioners call instead for using the criterion of 1.1 times MAOP based on verification of tool tolerance. Petition at 9-10.

PHMSA declines to amend the regulatory language for this specific immediate repair criteria for cracks as requested by Petitioners. The immediate repair criteria codified in the Final Rule were carefully selected, and their nuance calibrated, to provide robust protection from failure mechanisms of the sort that could result in another San Bruno-scale incident—which itself resulted from the degradation of an unremediated pipe seam weld flaw.[6] The repair conditions the Final Rule categorizes as immediate conditions are those anomalies posing the greatest risk of near-term integrity failure if unremediated.[7]

PHMSA chose the particular immediate repair criteria challenged by the Petitioners to provide a robust margin against integrity failures from crack or crack-like anomalies. Engineering modeling demonstrates that crack depth is a principal factor contributing to the potential for catastrophic integrity failure of cracks on a gas transmission pipeline, with the risk of catastrophic failure (as measured by predicted failure pressure) increasing markedly as crack depth approaches about 50% of the pipe wall thickness. PHMSA's selection in the Final Rule of the 1.25 times MAOP criterion at §§ 192.714(d)(1)(v)(C) and 192.933(d)(1)(v)(C) therefore functions as a backstop for the other immediate crack repair criteria in §§ 192.714(d)(1)(v) and 192.933(d)(1)(v) that are expressed in terms of crack depth or the ability of measurement tools to accurately determine crack depth; the particular threshold chosen provides a safety margin that can account for, among other things, predicted failure pressure calculation error and differences in characteristics (e.g., vintage, material composition, location) from one pipeline to the next.

PHMSA further notes that the Final Rule's choice of the 1.25 times MAOP threshold for such a backstop is consistent with other regulatory safety factors applied to pipeline facilities, with more protective safety factors employed as a function of location and vintage. See, e.g., § 192.619(a) (calculating MAOP). A more conservative MAOP-based threshold for immediate repair is appropriate to ensure adequate protection against crack anomaly failure for a number of reasons, including the following: variance in testing and tool sensitivity; crack degradation

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[6] National Transportation Safety Board ("NTSB"), NTSB/PAR-11-01, "Pipeline Accident Report: Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010," at xi (2011).

[7] In so doing, the repair regimes codified at §§ 192.714 and 192.933 provide a mutually reinforcing approach calibrating prescribed operator actions and timelines based on risk to public safety and the environment posed by an anomaly. By way of example, §§ 192.714(e) and 192.933(a) allow operators to consider circumstance specific factors to prioritize repairs, so long as they make "safety considerations for the public and operating personnel," take appropriate pressure reductions under §§ 192.714(e)(1), 192.933(a)(1), and document in records the justification for the reduction being consistent with that safety aim.

before discovery (given that assessments under §§ 192.710(b)(2) and 192.939(a) may not occur for ten or seven years, respectively) and scheduled repair[8]; and the need to account for temporary pressure excursions in excess of MAOP tolerated by PHMSA regulations (notwithstanding the general prohibition of sustained operation above MAOP).[9] Industry efforts evaluating risks associated with cracking failures underscore the value of having a more conservative, MAOP-based threshold prompting faster repair following crack detection. As one example, with cracks in the pipe body from stress corrosion cracking, ASME ST-PT-011 found that "failure may be imminent" as cracks approach a predicted failure pressure below 110% (or 1.1 times) MAOP without any safety factor applied.[10] The Final Rule's more demanding MAOP-benchmarked crack repair criterion is therefore appropriate and will help ensure safety and protection of the environment, and was based on data considered by PHMSA and its advisory committee. Further, PHMSA understands that the significant risks to public safety and the environment posed by cracks warrant a conservative, generically applicable, MAOP-based crack repair criterion rather than (as recommended by Petitioners) regulatory language explicitly providing operators a lower MAOP threshold attempting to account for either the universe of tolerances of various tools used by operators or idiosyncratic thresholds based on in-situ direct measurement of defect dimensions.

Lastly, the GPAC voting supports the use of the 1.25 times MAOP immediate repair criterion, as the GPAC recommended that such a criterion was "technically feasible, reasonable, cost-effective, and practicable."[11] Although GPAC requested that PHMSA "consider" an

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[8] PHMSA regulations at § 192.710(e) contemplate that operators could take as long as 180 days to obtain sufficient information to evaluate a discovered anomaly and categorize it as an immediate repair, scheduled repair, or monitored condition.

[9] See, e.g., §§ 192.201(a)(2) (minimum performance standards for pressure relieving and limiting stations pegged to 110% of MAOP or 75% of SMYS, whichever is lower), and 192.739(b) (inspection and test requirements for pressure limiting and regulating stations pegged to 104% of MAOP). These provisions require operators to employ design features and practices to avoid operation beyond MAOP for any appreciable length of time.

[10] 87 FR at 52248-49 (citing ASME, "STP–PT–011: Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas," at 10 (2008)).

[11] See GPAC March 26 to 28, 2018 Final Voting Slides at slides 21-22, available at https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=132. Petitioners suggest that PHMSA must explicitly discuss the technical feasibility, cost-effectiveness and practicability of the Final Rule's 1.25 times MAOP immediate crack repair criterion against each of the other elements of this rulemaking as well as previously-adopted elements of PHMSA's regulations. See Petition at 9-10 (contending that the 1.25 times MAOP criterion was overly conservative as it failed to account for provision within § 192.712(e)(2)(D) allowing operators to use a "conservative" default Charpy v-notch toughness value in connection with their fracture mechanics when actual values are unknown). Putting to one side whether such a procedural requirement could ever be practicable given PHMSA's comprehensive and highly technical regulatory regime, Petitioners provide no basis in statute or regulation for this alleged requirement beyond conclusory statements paraphrasing holdings from administrative law jurisprudence. Nor do Petitioners proffer any evidence that the interplay of other regulatory amendments in the Final Rule and current PHMSA regulations (including, but not limited to, § 192.712(e)(2)(D)—which by its terms is available only when actual values are unknown) were not considered by each of the GPAC in endorsing the Final Rule's immediate crack repair criterion or by PHMSA in adopting that criterion within the Final Rule. PHMSA notes that its part 192 regulations reflect a defense-in-depth approach to preventing and mitigating incidents on gas pipelines such that its consideration and adoption of any regulatory amendments are necessarily informed by pre-existing requirements and other regulatory amendments within the same rulemaking even if the preamble to a Final Rule does not discuss each and every pertinent regulatory provision. PHMSA further understands that the GPAC members review this and other rulemakings on the same basis.

alternative crack criterion of 1.1 times MAOP "after tool tolerance has been field verified and applied,"[12] the GPAC stopped short of recommending that alternative in lieu of the criterion PHMSA ultimately adopted or—as Petitioners seem to call for—regulatory language explicitly providing for relaxing of the 1.25 times MAOP threshold on a case-by-case basis as a function of verified tool tolerance. PHMSA did precisely what the GPAC recommended: it considered adopting such an alternative criterion, but declined to adopt it in favor of a more conservative, generically applicable 1.25 times MAOP criterion.[13] These findings, and the appropriate 1.25 safety margin, were calculated based on the available evidence before PHMSA and its advisory committee at the final rule stage; PHMSA notes that Petitioners may, as enhanced data with respect to tool tolerance becomes available, submit a petition for rulemaking pursuant to § 190.331 as they believe warranted for PHMSA's consideration.[14]

PHMSA understands, however, that Petitioners' ultimate objective is that operators have some flexibility to prioritize scheduling of repairs for conditions qualifying below the 1.25 times MAOP threshold. Indeed, that is precisely what the Final Rule permits. Under the regulatory provisions for repairs, immediate repair conditions must promptly be scheduled for repair, with an appropriate temporary pressure reduction meeting either of three methods for calculation under §§ 192.714(e)(1) and 192.933(a)(1)(i), as appropriate for safety to the public and operator personnel. The temporary pressure reduction framework set out at §§ 192.714(e)(1) and 192.933(a)(1)(i) allows for operator prioritization of repair conditions for up to one year with an appropriate temporary pressure reduction maintained, based on, among other things, public safety considerations, anomaly growth, location in relation to population density, potential customer impact, and weather-based access to the pipe location. PHMSA therefore finds no change to the Final Rule is necessary and will issue guidance to assist the regulated community in understanding PHMSA's expectations for temporary pressure reduction required upon discovery.

C. PHMSA declines to revise the Final Rule's requirements at § 192.714(b) governing use of predicted failure pressure as the upper limit for operating pressure during repairs and clarifies that this specific provision applies only "during repair operation."

Petitioners also criticize the § 192.714(b) requirement to lower operating pressure below PFP during repair activity as overly conservative, requesting instead use during repair activity of the same 20% reduction allowed by § 192.714(e)(1)(i) upon discovery of an immediate repair

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[12] By, for example, the use of unity plots as highlighted by Petitioners. Petition at 9.
[13] 87 FR at 52248.
[14] PHMSA understands that Petitioners and some of their members may believe that emerging technologies (e.g., electromagnetic acoustic transducers, or "EMAT" tools) for identifying and evaluating cracks are sufficiently precise to warrant a less demanding immediate crack repair criterion. However, at the time of the 2018 GPAC meetings, members of industry acknowledged that those technologies were not yet mature. See GPAC March 27, 2018 Transcript at 80 (comment of Andy Drake) ("So crack tools, ultrasonic tools, are on the edge of development right now and our ability to use them accurately is an experiment."), and 86-87 (comment of Cheryl Campbell), available at https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=132. Based on its own review in developing the Final Rule, PHMSA agrees with that assessment, even as some individual operators may have data suggesting improved precision from those technologies. PHMSA would be open to considering adjusting these limits as more comprehensive data becomes available demonstrating the technologies are proven.

condition. Petition at 23-24. The Final Rule's regulatory text contains two distinct pressure reductions: the temporary pressure reduction modes just set out in the paragraph above at § 192.714(e)(1) are calibrated for continued safe operation from the discovery of an anomaly until the repair may safely be conducted, while the operating pressure limit in § 192.714(b) recognizes that different safety considerations come in *during* the repair itself. The latter provisions apply only "during repair operations," which PHMSA will clarify in forthcoming guidance material.

PHMSA declines to amend § 192.714(b) to replace PFP as the upper bound for pressure reduction during repairs. Although in some cases the post-discovery generic 20% pressure reduction contemplated by § 192.712(e)(1)(i) may provide adequate margin for safety during repairs, in other cases it may not. Repair activity—which can involve on-site personnel in close physical proximity to the pipe being repaired, performing excavations, and physically modifying that pipe—justifies using conservative values that are based on the actual situation presented. Indeed, § 192.712(e)(1) acknowledges that a generic 20% pressure reduction may not even be the safest approach to reducing pressure at the moment of discovery (let alone during repairs with the additional considerations that come into play), as that generic reduction is but one of three permitted modes for temporary pressure reductions (some of which are pegged to PFP) on discovery of an immediate repair condition. PHMSA further notes that Petitioners provide no evidence to support their assertion that the use of PFP as the upper limit for operating pressure may not provide for safety.

D. PHMSA will issue a technical correction clarifying that the cross references at § 192.714(b) governing calculations explicitly reference certain procedures within § 192.712.

Petitioners contend that the regulatory language at § 192.714(b) establishing general operating pressure limits during repair operations references two provisions—§§ 192.712 and 192.607—with distinguishable procedural machinery for developing traceable, verifiable, and complete records of pipe and material properties when those records are unavailable. Petition at 21-23. Petitioners ask that PHMSA make clear by way of a regulatory amendment that operators may, for purposes of § 192.714(b), use the specific procedures in § 192.712(d)(3). Petition at 22. PHMSA understands this is already provided for in the regulatory text which, by referencing § 192.712, incorporates § 192.712(d)(3) as well as § 192.712(e)(2). Nonetheless, PHMSA recognizes the benefit to ensuring this understanding is reflected in the regulatory text itself at each of § 192.714(b) and analogous language at § 192.933(a), and PHMSA will effectuate that clarification through a forthcoming technical correction. Although Petitioners only ask specifically to include a reference within § 192.714(b) to § 192.712(d)(3), the latter provision applies for crack or crack-like anomalies after a pressure test, and PHMSA understands it is similarly appropriate to reference the procedure set forth in § 192.712(e)(2). PHMSA notes that both subparagraphs provide for appropriate procedures, depending on circumstance, to be used under § 192.712 until documented material properties are available.

An additional analysis set out at § 192.712(d)(1) provides the framework for use of engineering models to analyze crack or crack-like defects, which Petitioners misapprehend as

limited to a single material toughness model (Charpy v-notch toughness values). Petitioners therefore ask that other material toughness models (including material fracture toughness) be allowed as inputs under this provision. Petition at 22-23. The regulatory language at § 192.712(d)(1) provides for use of "a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other)" when analyzing crack or crack like defects. Section 192.712(d)(1) is not limited to Charpy v-notch toughness values, and in fact does not mention a specific model for the crack assessment (even as other regulatory provisions in § 192.712 may contemplate use of that model). Although § 192.712(d)(1) predates (and was unaffected by) the Final Rule, PHMSA clarifies that the "technically proven models" contemplated by § 192.712(d)(1) may include examples provided in the Petition of ASTM E1820 or BS 8571, as appropriate based on the circumstances.[15] PHMSA plans to issue guidance in the form of forthcoming frequently asked questions to clarify this understanding.

E. The material toughness default values in § 192.712 are appropriate—including as applied to crack and crack-like anomalies—and PHMSA declines to revise them.

Petitioners argue that the default material toughness values in § 192.712 (a provision that predates the Final Rule), when combined with the safety factor of 1.25 times MAOP for crack immediate repairs in the Final Rule's §§ 192.714(d)(1) and 192.933(d)(1), make the default (Charpy v-notch) toughness values overly conservative as applied in crack analysis pursuant to § 192.712(e)(2)(i)(D) such that one or another of those provisions should be amended. Petition at 23.

PHMSA declines to revise the procedures set out in § 192.712 allowing operators to safely operate by assessing potential anomalies without having to conduct destructive in-ditch assessments to obtain pipe material properties documented in traceable, verifiable, and complete records.[16] See 84 FR at 52192, 52194-95. PHMSA notes that the window for submitting a petition for reconsideration of the main of § 192.712's regulatory requirements (exclusive of subparagraphs (b) and (c) which the 2022 Final Rule amends) has closed, as § 192.712 was introduced by a rulemaking issued in October 2019. See 84 FR at 52251. Further, PHMSA

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[15] ASTM Int'l, ASTM E1820-23, "Standard Test Method for Measurement of Fracture Toughness" (Feb. 01, 2023); BSI Group, BS 8571:2018, "Method of test for determination of fracture toughness in metallic materials using single edge notched tension (SENT) specimens" (Nov. 30, 2018).

[16] PHMSA has made this point before. See, e.g., 87 FR at 52253 ("In the Response to Petitions for Reconsideration on the 2019 Gas Transmission Rule, PHMSA stated that if operators are missing any material properties during anomaly evaluations and repairs, operators must confirm those material properties under §§ 192.607 and 192.712(e) through (g). For consistency in this Final Rule, and to make this requirement more explicit, PHMSA has linked those material property confirmation requirements to the anomaly repair requirements by cross-referencing § 192.607 at both §§ 192.714 and 192.933."); "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments: Responses to a Joint Petition for Reconsideration," 85 FR 40132, 40133 (July 6, 2020) ("[I]f operators are missing any material properties during anomaly evaluations and repairs, operators must confirm those material properties under §§ 192.607 and 192.712(e) through (g)."); "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," 84 FR 52180, 52181 (Oct. 1, 2019) ("This rule also requires operators of certain onshore steel gas transmission pipeline segments to reconfirm the MAOP of those segments and gather any necessary material property records they might need to do so, where the records needed to substantiate the MAOP are not traceable, verifiable, and complete.").

notes that pipeline characteristics are essential inputs in evaluating anomalies by way of engineering assessments of PFP and remaining life, which in turn ensure confidence in the safety of the tiered repair condition schedules in §§ 192.714(d) and 192.933(d). The most accurate engineering analysis of a potential anomaly will use a pipeline's actual material characteristics, which PHMSA regulation requires be documented in traceable, verifiable, and complete records (i.e., documented material property records). See § 192.607. However, material property verification by destructive inspection can be costly and time consuming, so PHMSA determined it would be appropriate to allow an opportunistic method for verifying and documenting these records, as PHMSA explained in the Final Rule "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments Gas." See 84 FR at 52192-95. Facilitating this opportunistic method, § 192.712 sets out default values in § 192.712(e)(2)(i) (i.e., Charpy v-notch toughness values) operators can use until documented material property records are available.

As the regulatory text itself notes, these Charpy v-notch toughness values are *intended* to be conservative, one-size-fits-all, default values, and they were always intended to be used in a manner that supplements whatever other (implicit or explicit) safety factors are embedded in other regulatory provisions within which these values may be employed.[17] An operator wishing to avoid such additional conservativism from the use of such default values can always document (and then use) material properties under § 192.607. Moreover, § 192.712(e)(2)(i)(E) permits operators to seek PHMSA review pursuant to § 192.18 of the use of other appropriate values employing similar conservatism.[18] Furthermore, the Petition sets forth no basis for different values to be employed that would allow operators to conduct meaningful engineering analyses informing their assessment.

F. PHMSA declines to revise the dent reassessment safety factor of "5 or greater" prescribed in the Final Rule at § 192.712(c)(9).

Petitioners contend that PHMSA's codification at § 192.712(c)(9) of a dent reassessment safety factor of "5 or greater" was neither noticed for comment in the NPRM, specifically addressed in GPAC discussions, nor explained as a superior option to alternatives. Petition at 14-16. Petitioners call for either removal of any reference to a dent reassessment safety factor from that provision or use of a less demanding safety factor of 2.

A reassessment safety factor is an integral element in the engineering critical assessment ("ECA") procedures that industry commenters—including Petitioners—requested be integrated into the rulemaking's dent repair evaluation procedures as an alternative to the one-size-fits-all-approach that had been in the proposed rulemaking and present in existing regulations. The GPAC subsequently endorsed the use of ECA procedures as an alternative approach to evaluating dents.[19] Subsequently, a consensus industry standard (API RP 1183) underscored the importance of a reassessment safety factor within the ECA, recommending use of factors

[17] PHMSA explained the basis for the default values set out in § 192.712 (and specifically § 192.712(e)(2)(D)) in the rulemaking codifying them. See 84 FR at 52236-37 (explaining basis for these values).
[18] Operators may also use, under § 192.712(e)(2)(i)(A), "Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer[.]"
[19] GPAC March 26 to 28, 2018 Final Voting Slides at slide 20.

between 2 and 5.[20] PHMSA within § 192.712(c)(9) of the Final Rule adopted the more conservative reassessment safety factor of 5 as a baseline.[21]

PHMSA therefore declines to remove reference to the use of a reassessment safety factor from § 192.712(c)(9), as that is an important element of the ECA approach Petitioners themselves requested be included in the Final Rule. PHMSA similarly declines to remove the specific reassessment safety factor of 5 prescribed in the Final Rule, as that value has been endorsed for use by the pertinent consensus industry standard. Although PHMSA had considered the use of a reassessment safety factor of 2, it selected the more conservative safety factor value in light of the potential for significant variations among ECA outputs based on different fatigue models employed and the characteristics of pipe and anomalies being evaluated. Indeed, in reviewing ECA analysis on dents submitted by operators seeking special permits, PHMSA has observed wide variation in the fatigue life for the same dents depending on the fatigue model employed. If an operator has a safety-based rationale to employ an alternative safety factor (e.g., less than 5) on a given anomaly, that operator may seek PHMSA permission to use that lower reassessment safety factor as an alternate engineering critical assessment procedure in their dent evaluation in accordance with § 192.712(c)(11) and § 192.18, which PHMSA also plans to clarify in forthcoming guidance.

G. PHMSA declines to eliminate references to "corrosive constituents" from § 192.478 governing internal corrosion evaluation, monitoring, and mitigation requirements.

Petitioners request that PHMSA replace language in the Final Rule's new § 192.478 referring to "corrosive constituents" with language referring to "corrosive gas." Petition at 10-14. Petitioners contend that this language is inconsistent with language used in other provisions in PHMSA regulations and will prove impracticable given that the presence of potentially corrosive constituents in gas streams alone may not contribute to internal corrosion. Petitioners also contend that gas quality monitoring is the prerogative of the Federal Energy Regulatory Commission ("FERC") rather than PHMSA, as gas quality—and the presence of potentially corrosive constituents in a gas stream—is a commercial term of service within FERC-approved tariffs. Petitioners also assert that § 192.478(b) monitoring and mitigation requirements reflect a misapprehension regarding how corrosive constituents are currently introduced and monitored within gas streams.

Internal corrosion—to which corrosive constituents within a gas stream can contribute in certain circumstances—is a significant threat to pipeline integrity warranting robust safety measures. And as explained in the Final Rule, existing PHMSA regulations do not explicitly (and adequately) address this integrity threat.[22] It is those circumstances where pipelines are

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[20] API, Recommended Practice 1183, "Assessment and Management of Dents in Pipelines," at 72 (1st Ed. Nov. 2020) ("API RP 1183").
[21] 87 FR at 52249-50.
[22] Nor, for that matter, do FERC regulations or tariff conditions adequately address this risk; by way of example, an incident on an interstate (FERC-regulated) gas transmission line operated by Transcontinental Gas Pipe Line Company arose in part by from internal corrosion resulting from the intrusion of salt water within the gas stream. "In the Matter of Transcontinental Gas Pipe Line Company, LLC, CPF 1-2018-1005 (June 19, 2019), https://primis.phmsa.dot.gov/comm/reports/enforce/documents/120181005/120181005_Final%20Order_06192019.pdf.

transporting corrosive gas which § 192.478 addresses by ensuring operators account for the interaction of constituents that, in given combinations, can make the gas corrosive.

The Final Rule's requirements at § 192.478 address the risk of internal corrosion by enhancing awareness of the safety dimension of the presence of constituents in gas streams that may make the gas corrosive. That risk is not limited to gas streams consisting entirely (or even predominantly) of corrosive gas, but can exist in a variety of gas streams and is based on an operator understanding the levels and interaction of constituents identified in § 192.478(a)—carbon dioxide, hydrogen sulfide, sulfur, microbes, and water—along various points in their gas stream. In response to that threat to pipeline integrity, § 192.478 neither prohibits nor prescribes specific limits on the amount of particular constituents within gas streams (much less prohibit mixing of gas streams) in a way that would approach FERC's jurisdictional responsibilities with respect to the commercial terms of service for gas transmission pipelines. Rather, it will ensure operators leverage information they have historically developed for commercial purposes to develop appropriate controls to manage the safety risks associated from potentially corrosive gas constituents within the gas stream. Further, each of the qualifications (e.g., "where applicable" and "as necessary") at § 192.478(a) responsive to GPAC recommendations account for the fact that the mere presence of potentially corrosive constituents in the gas stream does not mean that internal corrosion is an inevitable result; rather, corrosion rates will turn on a number of variables (other constituents, temperature, partial pressures of potentially corrosive constituents, etc.). It is the presence of those potentially corrosive constituents that individually or, particularly, in combination with each other, and based on partial pressure levels, may corrode the gas. If an evaluation yields that potentially corrosive constituents, when considered alongside those other variables could be expected to result in internal corrosion—such that the operator is transporting gas which is corrosive—the operator would under § 192.478(b) need to implement monitoring and mitigation programs tailored to the precise risks the operator identified. Nothing within § 192.478 states that such monitoring and mitigation programs must necessarily result in changes in the composition of the gas streams.

PHMSA acknowledges that not every operator may already have gas constituent monitoring capacity—or take periodic gas stream samples—at each and every receipt point along a pipeline. However, as discussed above, PHMSA's revisions to the Final Rule in response to the GPAC discussion do not require every pipeline to integrate comprehensive monitoring and mitigation requirements. However, for those pipelines in which potentially corrosive constituents have been evaluated to entail a risk of internal corrosion, robust monitoring and mitigation measures of the sort required by § 192.478(b) would be necessary to ensure pipeline safety.

H. PHMSA declines to amend § 192.473(c)(4) timelines to complete remedial action following performance of an interference survey but will consider in future rulemaking allowing flexibility by way of § 192.18 notification, and will issue a targeted enforcement discretion for certain circumstances where an operator is delayed from completing remedial action.

Petitioners criticize the 15-month timeline requirement in § 192.473(c) for operators to complete remedial actions following unsatisfactory interference surveys as impracticable due to

permitting delays, the need to compile and evaluate data, and the need to design and install effective interference mitigation. Petition at 18-19. Petitioners consequently request PHMSA amend § 192.473 to allow operators to request additional time using the process in § 192.18 to complete the remedial actions.

PHMSA expects that the 15-months provided in the Final Rule for operators to conduct the remediation is sufficient time, balancing the need to account for the variety of circumstances a remediation project may present, while providing clear timelines within which operators will need to remediate accelerated corrosion from interference currents. Indeed, the 15 months provided for remediation in the Final Rule is longer than the 12 months recommended by the GPAC, in part because the 15 months anticipates and preemptively includes additional time for delayed permitting.[23] Nonetheless, PHMSA understands that there could be an instance where, due to no fault of its own, an operator makes good faith attempts to complete remedial action but is unable to do so within the 15-month period. These include: (1) an operator which timely applies for, and diligently pursues, permits to conduct remedial actions but does not receive one or more necessary permits from the pertinent regulatory authority(ies) allowing it to complete remedial actions within the 15-month period; (2) notwithstanding an operator's timely and diligent efforts, where a third-party delays an operator in acquiring access to rights-of-way necessary to conduct remedial action; or (3) where, during or after initial remediation efforts, the operator receives other interference current survey findings which require further remediation that may delay completion of ongoing remediation actions. PHMSA will, therefore, consider in a future rulemaking whether to include flexibility within § 192.473(c)(4) allowing an operator to document and notify PHMSA under § 192.18 of a basis necessitating additional remedial time, but does not believe it would be appropriate to make such a regulatory change in response to a petition for reconsideration. In the meantime, PHMSA will issue a forthcoming limited notice of enforcement discretion not to enforce violations of the 15-month period against operators who have undertaken good faith, diligent efforts—which are documented by the operator—which in the above three specific scenarios leaves it unable to complete remedial action within the 15-month period prescribed in the Final Rule.

I. PHMSA declines to remove requirements in §§ 192.714(d)(1)(iv) and 192.933(d)(1)(iv) obliging operators to consider as an immediate repair condition certain metal loss preferentially affecting longitudinal seams on high-frequency electric resistance welded pipe.

Petitioners criticize as unsupported language at §§ 192.714(d)(1)(iv) and 192.933(d)(1)(iv) considering as an immediate repair condition metal loss preferentially affecting longitudinal seams on high-frequency electric resistance welded ("HF-ERW") pipe, where the predicted failure pressure ("PFP") is less than 1.25 times the Maximum Allowable Operating Pressure ("MAOP"). Petition at 16-18. Petitioners note that although PHMSA alluded to historical incident data supporting this characterization, Petitioners' review of that data between 2010-2017 yielded no examples of the particular failure mechanisms (corrosion or

[23] GPAC June 6 to 7, 2017 Meeting Slides at slide 27, available at https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=123; see 87 FR at 52237 (noting the time period was lengthened, in part, due to comments suggesting this to account for potential difficulties in obtaining the proper permits).

environmental corrosion cracking) that they understood to be the basis for PHMSA's categorization as an immediate repair condition. Petitioners do not request reconsideration of immediate repair conditions involving metal loss preferentially affecting longitudinal seams formed by other methods, including low-frequency electric resistance welding ("LF-ERW"), as they assert that the HF-ERW method has a significantly lower risk profile compared to those other forming methods.

PHMSA declines to amend §§ 192.714(d)(1)(iv) and 192.933(d)(1)(iv) as requested in the Petition. PHMSA subject-matter experts identify that HF-ERW pipe can be susceptible to similar manufacturing flaws found in LF-ERW pipe which entail heightened vulnerability to cracking when corrosion is introduced at the longitudinal seam. In response to recommendations from the National Transportation Safety Board ("NTSB") following a catastrophic failure of ERW pipe in Carmichael, MS, PHMSA commissioned leading experts to conduct studies into reliability of all types of ERW pipe.[24] Those findings included that, while the Carmichael explosion was on a transmission pipe manufactured in 1961 using the LF-ERW method,[25] it is likely that "the underlying concerns of the NTSB . . . apply equally to the [HF-ERW pipe]."[26] PHMSA therefore understands metal loss preferentially affecting longitudinal seams on HF-ERW pipe can merit characterization as an immediate repair condition just as it would for longitudinal seams on LF-ERW pipe.[27]

Although LF-ERW methods have been used in making pipe for decades, manufacturers increasingly shifted to producing pipe using HF-ERW in the late 1960s and 1970s.[28] While seam strength and reliability have generally increased on HF-ERW pipe manufactured over the past 50 years, HF-ERW pipe has continued to experience seam failures (albeit admittedly at a lower rate than LF-ERW pipe).[29] PHMSA understands this is because seam strength in any ERW-manufactured pipe does not turn solely on whether high-frequency or low-frequency techniques are introduced at the weld, nor solely on the year of manufacture; rather, manufacturer-controlled variables (such as heat consistency in the weld, the quality of skelp used and the quality of skelp edges), vintage, and other quality controls and technological innovations in manufacturing are

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[24] The full record is available at: PHMSA Research & Development Program, "Comprehensive Study to Understand Longitudinal ERW Seam Failures," https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.

[25] NTSB, "Rupture of Hazardous Liquid Pipeline with Release and Ignition of Propane, Carmichael, Mississippi, November 1, 2017," Accident Report, NTSB/PAR-09/01, at 20 (Oct. 14, 2009).

[26] B. N. Leis & J. B. Nestleroth, Battelle, Task 1.4, "Battelle's Experience with ERW and Flash Weld Seam Failures," at 66 (Sept. 20, 2012), https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=7885 ("Battelle, Task 1.4").

[27] 87 FR at 52268; *Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines*, 81 FR 20722, 20728 (Apr. 16, 2016); B. N. Leis, Battelle, Task 4.2, "Time-Trending and Like-Similar Analysis for ERW-Seam Failures," at 21 (June 30, 2013), https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=8421 ("Battelle, Task 4.2") ("[T]he HF seam processes can be prone to many of the same types of anomaly that have been experienced with LF ERW seams.").

[28] Battelle, Task 1.4 at 7.

[29] Battelle, Task 1.4 at 28 ("While the trends for production since the 1970s remain low, it should be noted that several failures have occurred in the 1990s and since that are known to Battelle . . . . The point in this context is that while the frequency of failures has declined significantly, vigilance and quality remain essential elements in making quality steel and in producing quality line-pipe."); see also National Energy Board Safety Advisory (Canada), NEB SA 2019-01, "Potential for Low Toughness and Lack of Fusion of Weld Zone in Hyundai API 5L Electric Resistance Weld (Hyundai API 5L ERW) Pipe," (July 3, 2019) (noting several incidents of failure on U.S.-installed HF-ERW pipe manufactured by Hyundai Steel between 2014 to 2015).

important factors as well.[30] HF-ERW pipe, therefore, remains subject to similar weld failure mechanisms as LF-ERW pipe, including cold welds, hook cracks, and selective seam corrosion (i.e., corrosion in the longitudinal seam) due to skelp material quality, skelp edge prep and alignment, and heat during and after welding.[31] HF-ERW methods may also be prone to defects to which other forming methods are not particularly susceptible.[32] These defects make a longitudinal weld seam weaker, in turn increasing the risk of integrity failures of the seam from corrosion, fracture, or cracking.

PHMSA subject matter experts reviewed data within PHMSA's database of historical incidents and compiled by outside experts and concluded that failures on HF-ERW pipe can be a significant safety risk meriting inclusion as an immediate repair criteria.[33] Because HF-ERW pipe can entail similar risk as pipe formed by other methods (including LF-ERW pipe) of integrity failure along longitudinal seams evincing preferential metal loss, PHMSA understands such metal loss warrants characterization as an immediate repair condition within §§ 192.714(d)(1)(iv) and 192.933(d)(1)(iv). As PHMSA understands that manufacturing conditions on the whole can lead certain vintages and manufacturers of ERW pipe to represent a greater risk to preferential metal loss on longitudinal seams than other vintages of HF-ERW pipe, PHMSA will consider, based on published results of a forthcoming INGAA Foundation study and any other publicly available studies, whether focusing operator compliance efforts on those more at risk HF-ERW pipelines would be appropriate.

J. PHMSA declines to revise § 192.917(b) to delete the requirement for gas transmission operators subject to subpart O integrity management requirement to gather and integrate "pertinent" data as part of their threat identification efforts, but addresses Petitioners' concern by clarification and forthcoming guidance.

Petitioners call for removal of language in § 192.917(b) characterizing the obligation of subpart O-regulated pipeline operators to collect and integrate data within their threat identification efforts in terms of "pertinent" data. Petition at 25. Petitioners contend that the

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[30] Battelle, Task 1.4 at 22 ("But even with such controls, failures have continued, albeit at reduced rates. In addition to the occurrence of cold welds, hook cracks, and SSC (or grooving corrosion), there are some defect types that are appear unique to the high frequency process. In summary, good steel and a good seam give rise to good pipe[.]"). These factors depend on the manufacturer and its operating conditions and methods. See E.B. Clark, et al., Battelle, "Integrity Characteristics of Vintage Pipelines," The INGAA Foundation, Inc., at 23 tbl. 6 (2005), https://www.ingaa.org/File.aspx?id=6145 (showing heightened ERW failure rates based on manufacturer).

[31] Battelle, Task 4.2 at iv, 21 ("the LF and HF processes are inherently similar and so can develop many of the same types of anomalies that trace to setup and process upsets or the use of lower-quality skelp"); Battelle, Task 1.4 at 11-17; Robert K. Nichols, Thermatool, Corp., "Common HF Welding Defects," at 2, 4, available at https://www.thermatool.com/resources/technical-papers/ (observing failure methods found on HF-ERW pipe and finding that this type of pipe can "present the operator with a bewildering variety of weld defects").

[32] Battelle, Task 1.4 at 22 ("there are some defect types that are appear unique to the high frequency process").

[33] Battelle, Task 1.4 at Annex A; GPAC March 2, 2018 Meeting Slides at slide 59, available at https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=131 (noting 10 incidents on HF-ERW between 2010 and 2017, with 10 more incidents on ERW for which the frequency could not be verified, compared with 15 incidents on LF-ERW pipe); J.F. Kiefner & K.M. Kolovich, Battelle, Final Report No. 12-139, "ERW and Flash Weld Seam Failures," at 13 tbl. 6 (Sept. 24, 2012), https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=7684 (finding in a large study 48 failures on HF-ERW pipes, compared with 153 on LF-ERW pipes); see generally Kiefner & Kolovich, "ERW and Flash Weld Seam Failures" (compiling incidents of failure for various vintage ERW pipe).

"pertinent" language is overbroad, as it may require collection of data with little value for threat identification, while at the same time potentially excluding consideration of other probative data in identifying and assessing pipeline integrity threats.

PHMSA finds Petitioners' arguments unconvincing. The Final Rule at § 192.917(b)'s introductory text language contemplates broad ("could be relevant") information collection requirements commensurate with the broad scope of the threat identification analysis that is the initial scoping step within subpart O-compliant integrity management programs. The Final Rule's introduction of the "pertinent" qualification at § 192.917(b) and (b)(1) functions to limit operator's obligations to integrate some of that collected data within the threat assessment analysis. Precisely what data is "pertinent" turns on whether the data falls within the prescribed list at § 192.917(b)(1) or whether the operator—who is best-positioned to identify information warranting integration within the threat assessment analysis for a particular pipeline—identifies it as pertinent. Said another way: whether the operator deems specific information as relevant, given that an "integrity management program should be customized to meet each operator's unique conditions."[34] PHMSA also notes that the "pertinent" language used in § 192.917(b) is consistent with the use of that language within the discussion of threat assessment in consensus industry standards for integrity management programs.[35]

PHMSA understands that this approach memorialized in § 192.917(b) addresses Petitioners' concerns without modification and will issue clarifying guidance reflecting the same.

K. PHMSA declines to revise the regulatory definition of "in-line inspection" at § 192.3 and will issue guidance clarifying that it can include free-swimming tools.

49 CFR 192.3 defines "in-line inspection" as "an inspection of a pipeline from the interior of the pipe using an inspection tool also called intelligent or smart pigging. This definition includes tethered and self-propelled inspection tools." 87 FR at 52267 (emphasis in original). Petitioners request clarification that the § 192.3 regulatory definition of "in-line inspection" ("ILI") as used within §§ 192.710(a)(2) and 192.624(a)(2)(iii) encompasses free-swimming tools. Petition at 19-21.

PHMSA grants this request for clarification and confirms that this understanding is correct, without any need for regulatory change. The § 192.3 definition of ILI in the Final Rule was intended to clarify that operators are free to use tethered and self-propelled tools in addition to "free-swimming" or "piggable" ILI tools. The Final Rule was not intended to modify the meaning of a piggable (i.e., free-swimming) ILI tool for moderate consequence areas established

[34] ASME, B31.8S-2004, "Managing System Integrity of Gas Pipelines," sec. 1.3 (2005) ("ASME/ANSI, B31.8S").
[35] PHMSA hopes and expects that operators will consider that data which is relevant for their pipelines, from the threats identified, and also considering additional data of which the operator may be aware. See ASME/ANSI B31.8S, sec. A3.5 ("During the integrity assessment and mitigation activities, the operator may discover other data that may be pertinent to other threats. This data should be used where appropriate for performing risk assessments for other threats."). "By analyzing all of [this] pertinent information, the operator can determine where the risks of an incident are the greatest, and make prudent decisions to assess and reduce those risks." ASME/ANSI B31.8S, sec. 1.3.

in an earlier rulemaking referenced in the Petition.[36] PHMSA will memorialize that common understanding within forthcoming guidance on the Final Rule.

L. PHMSA finds it unnecessary to amend the references to "uprate" in §§ 192.714(d)(2) and 192.933(d)(2).

Several repair conditions in each of §§ 192.714(d) and 192.933(d) calibrate mandatory repair timelines based on the risk to human population as expressed in reference to class location and (by extension) PFP. For example, a crack anomaly with a calculated PFP less than 1.39 times MAOP is a scheduled repair condition when located in a Class 1 location, while a Class 2 location would entail a scheduled repair condition only when PFP is less than 1.5 times MAOP. See § 192.714(d)(2)(vii).

Petitioners argue that language in each of these scheduled repair conditions to Class 1 pipe in Class 2 locations that has been "uprated in accordance with § 192.611" is incorrect because "Section 192.611 does not govern uprating a pipeline." Petition at 28. PHMSA determined that no change in the Final Rule text is necessary, as the reference to § 192.611 conveys that "uprate" in context pertains to change in class location rather than an "uprate" pursuant to subpart K of part 192.

M. PHMSA finds no basis to amend provisions pertaining to direct examination and indirect inspection in Stress Corrosion Cracking (SCC) Direct Assessment (SCCDA) plans for pipelines in HCAs.

Petitioners request reconsideration of the phrase "covered pipeline segment" in § 192.929(b)(3) as they believe it alters the meaning from the proposed regulatory text that would have required a minimum of "three direct examinations within the SCC segment." Petition at 26-27. However, both the proposed § 192.929(b)(3) and the final amended § 192.929(b)(3) are located in subpart O, which applies integrity management requirements to operators of "covered pipeline segments" to address risk on those covered pipeline segments. See § 192.907. Similarly, both the proposed and final versions of § 192.929(b)(3) require operators to conduct three SCCDA direct examinations in those covered pipeline segments. See also 81 FR at 20844 (proposed § 192.929(b)); 87 FR at 52276 (final amended § 192.929(b)). PHMSA therefore does not understand there to be a substantive difference between the meaning of the proposed and final versions arising from the inclusion in the final text of "SCC within a covered pipeline segment."

Relatedly, Petitioners ask for reconsideration of the Final Rule's indirect inspection step within an SCCDA plan at § 192.929(b)(2) to, in their view, "better align" with industry standard NACE SP0204 and allow for indirect inspections to include ILI tools. Petition at 27. The § 192.929(b)(2) regulatory text begins "In addition to NACE SP0204" and merely adds the minimal number of surveys to conduct (at least two) in following NACE SP0204 for the indirect inspections. The Final Rule, therefore, explicitly incorporates the NACE SP0204 standard for operators to follow in establishing indirect inspection procedures as Petitioners request. See also § 192.929(b) (providing that all aspects of the SCCDA plan "meet NACE SP0204."). The

[36] 84 FR at 52215-16.

indirect inspection stage of an SCCDA procedure is conducted by above ground surveys using "the complementary measurement tools most appropriate for the pipeline segment," which could include (in the pipe) ILI tool results as one of the survey methods, as explicitly permitted in §§ 192.921(a)(1), 192.937(c)(1).

N. PHMSA will address certain other concerns of the Petitioners in a forthcoming technical correction Federal Register notice and implementing guidance.

PHMSA also grants the Petition in several respects and will make a series of clarification or technical correction of certain language in the Final Rule. In addition to the technical correction discussed in section D above, PHMSA addresses the remaining requests in turn below.

1. PHMSA will issue a technical correction to add in § 192.714(d)(1) a reference to ASME/ANSI B31.8S, section 7.

Petitioners ask PHMSA to make a correction to the Final Rule at § 192.714(d)(1) to add an explicit reference to ASME/ANSI B31.8S, section 7 so as to incorporate its 5-day provision for evaluating, and thereafter repairing, immediate repair conditions. Petition at 27.[37] Petitioners suggest that the omission of a reference to ASME/ANSI B31.8S, section 7 from § 192.741(d)(1) was an oversight because that provision's integrity management analogue (§ 192.933(d)(1)) contains such a reference.

PHMSA agrees that the omission of a reference within § 192.714(d)(1) to ASME/ANSI B31.8S, section 7 was an editorial oversight, as that provision was intended to mirror the language in § 192.933(d)(1). PHMSA will therefore issue a technical correction addressing this inadvertent omission.

2. PHMSA will issue a technical correction to § 192.714(d)(3)(i) to incorporate language inadvertently omitted from that subparagraph but included within other subparagraphs of § 192.714 governing critical strain analysis of monitored dents.

Petitioners request PHMSA make a correction to § 192.714(d)(3)(i) in the Final Rule to correct what they contend was an inadvertently omitted exception ("unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded") from the requirement to treat certain dents as monitored repair conditions. Petition at 25-26. Petitioners note that this exception was, in contrast, included in the Final Rule's amendments to integrity management requirements at § 192.933(d)(3)(i).

PHMSA agrees that the omission from § 192.714(d)(3)(i) of the exception language was a drafting error. PHMSA further notes that similar language is employed not only at § 192.933(d)(3)(i), but also other Final Rule provisions governing monitoring of dent conditions at §§ 192.714(d)(3)(ii)–(iv) and 192.933(d)(3)(ii)–(iv). And references to critical strain level also appear within the Final Rule's provisions at §§ 192.714(d)(2)(i)–(iii) and 192.933(d)(2)(i)–(iii)) prioritizing repair of those dents which demonstrate exceedance of critical strain levels.

[37] ASME/ANSI, B31.8S, sec. 7.

PHMSA will therefore issue a technical correction addressing this inadvertent omission to § 192.714(d)(3)(i).

3. PHMSA will issue a technical correction to § 192.319 to clarify that operators will have 6 months following assessment, or receiving necessary permits, to repair severe coating damage.

Petitioners request PHMSA correct a timing discrepancy within § 192.319. Specifically, Petitioners note that § 192.319(d) obliges operators to perform corrosion coating assessments on newly installed pipe promptly "but not later than 6 months after placing the pipeline in service"; however, paragraph (f) of the same provision requires operators to repair any severe coating damage found in that assessment within the same 6 months after the pipe is placed into service (or as soon as practical after obtaining necessary permits). Petition at 24-25. Petitioners further note that other provisions of the Final Rule (§ 192.461(f) and (h)) pertaining to coating assessment following excavation and backfill activity provide 6 months to complete a coating assessment, with a second 6-month period following assessment to complete any coating repairs. Petitioners request PHMSA correct this anomaly by revising § 192.319(f) to peg the 6-month coating repair requirement to completion of an assessment (or as soon as practical after obtaining necessary permits).

PHMSA agrees that the timing discrepancy at § 192.319 was unintentional; the timing requirements at § 192.319 were intended to mirror those at § 192.461(f) and (h). PHMSA will correct the error in § 192.319(f) in a forthcoming *Federal Register* notice.

4. PHMSA notes that the equation for defining "wrinkle bend" at § 192.3 has been corrected.

Petitioners note that the Final Rule's definition of "wrinkle bend" at § 192.3 omitted a formula that appeared in the NPRM and which the Final Rule's narrative discussion assumes were retained. Petition at 28. On October 25, 2022, the *Federal Register* issued a correction to a printing error, which restored the complete definition of "wrinkle bend" in § 192.3.[38]

5. PHMSA will issue a technical correction to clarify references to "amps per meter squared AC" within § 192.473(c)(3).

Petitioners point out that the qualification "AC" was inadvertently omitted from the description within § 192.473(c)(3) of the unit employed when measuring interference survey results to inform remedial action. Petition at 29. PHMSA will correct this omission in a forthcoming *Federal Register* notice.

O. PHMSA will address other issues raised in the Petition in forthcoming guidance on the Final Rule.

To the extent there remain any other issues in the Petition—whether styled in the Petition as requests for "reconsideration," "correction," or "clarification"—best classified as

[38] 87 FR 64384 (Oct. 25, 2022).

clarifications sought by Petitioners,[39] PHMSA intends to address these and other topics discussed in this letter in forthcoming implementing guidance material for the public. PHMSA will in the summer of 2023 publish in the *Federal Register* a notice of draft guidance (in the form of frequently asked questions), which Petitioners, their members, and the public will be able to provide comment on for consideration in final guidance on these topics.

P. Conclusion.

PHMSA acknowledges Petitioners and their members have made meaningful contributions to PHMSA's decade-long development of this critically important rulemaking implementing lessons learned from the 2010 San Bruno incident. To the extent operators or their trade associations accumulate enhanced data or information while applying any aforementioned regulatory provision, they are welcome to submit for PHMSA's consideration a petition for rulemaking pursuant to § 190.331 as they believe warranted. PHMSA looks forward to working closely with the Petitioners in the timely implementation of the common-sense and long-overdue safety requirements within the Final Rule.

Sincerely,

Alan K. Mayberry
Associate Administrator for Pipeline Safety
Pipeline and Hazardous Materials Safety Administration

[39] These remaining topics include the definition of "systemic" and "non-systemic" in § 192.465(f); and the meaning of growth prior to the next scheduled assessment in § 192.933(d)(3).

Dated: April 18, 2023.

Daniel Rosenblatt,

Acting Director, Registration Division, Office of Pesticide Programs.

Therefore, for the reasons stated in the preamble, EPA is amending 40 CFR chapter I as follows:

PART 180—TOLERANCES AND EXEMPTIONS FOR PESTICIDE CHEMICAL RESIDUES IN FOOD

■ 1. The authority citation for part 180 continues to read as follows:

Authority: 21 U.S.C. 321(q), 346a and 371.

■ 2. In § 180.960, amend table 1 to the section by adding, in alphabetical order, the polymer "α-D-Glucopyranoside, β-D-fructofuranosyl, polymer with methyloxirane and oxirane with a minimum number average molecular weight (in amu) of 9,800" to the table to read as follows:

§ 180.960 Polymers; exemptions from the requirement of a tolerance.

* * * * *

TABLE 1 TO § 180.960

Polymer	CAS no.
* * * * * *	*
α-D-Glucopyranoside, β-D-fructofuranosyl, polymer with methyloxirane and oxirane with a minimum number average molecular weight (in amu) of 9,800	26301–10–0
* * * * * *	*

[FR Doc. 2023–08584 Filed 4–21–23; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket No. PHMSA–2011–0023; Amdt. No. 192–133]

RIN 2137–AF39

Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments: Technical Corrections; Response to Petitions for Reconsideration

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Final rule; technical corrections; response to petitions for reconsideration.

SUMMARY: PHMSA is making necessary technical corrections to ensure consistency within, and the intended effect of, a recently issued final rule titled "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments." PHMSA also alerts the public to its November 18, 2022, and April 19, 2023, responses to petitions for reconsideration of this final rule.

DATES: Effective May 24, 2023.

FOR FURTHER INFORMATION CONTACT: *Technical questions:* Steve Nanney, Senior Technical Advisor, by telephone at 713–272–2855.

General information: Robert Jagger, Senior Transportation Specialist, by telephone at 202–366–4361.

SUPPLEMENTARY INFORMATION: On August 24, 2022, as the culmination of a decade-long rulemaking process, PHMSA published a final rule titled "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments" [1] amending the Pipeline Safety Regulations at 49 CFR part 192 to improve the safety of onshore gas transmission pipelines. In preparing to implement provisions of the August 2022 Final Rule, as well as through discussions with stakeholders (including petitions for reconsideration of the August 2022 Final Rule), PHMSA has identified several places in the amended regulatory text that would benefit from technical correction to facilitate timely implementation of the August 2022 Final Rule consistent with the function and purposes described in the administrative record. PHMSA also alerts the public to the availability in the rulemaking docket of its November 18, 2022, response to a petition for reconsideration filed by the American Gas Association and its April 19, 2022, response to a petition for reconsideration jointly filed by the Interstate Natural Gas Association of America and the American Petroleum Institute.

[1] 87 FR 52224 (Aug. 24, 2022) ("August 2022 Final Rule").

A. Technical Corrections To Ensure Consistency Between §§ 192.714 and 192.933

Among the August 2022 Final Rule's regulatory amendments were the enhancement of existing repair criteria and repair schedules for anomalies discovered in a High Consequence Area (HCA) and the extension of those repair criteria and schedules to onshore gas transmission lines outside an HCA. *See* 87 FR at 52226 ("The content of the non-HCA repair criteria being finalized in this rule is consistent with the criteria for HCAs"). This was achieved by adding similar repair criteria and scheduling requirements to both 49 CFR 192.714 (applicable to non-HCA lines) and § 192.933 (applicable to HCA lines). *See* 87 FR at 52246. However, PHMSA has identified three instances in the amended regulatory text that would benefit from technical correction to facilitate timely implementation of the August 2022 Final Rule consistent with the function and purposes described in the administrative record.

First, both §§ 192.714 and 192.933 provide, at respective paragraph (d)(1), for specific conditions that must be repaired immediately. These are the most severe, risk-bearing conditions and the August 2022 Final Rule set out the importance for public and environmental safety of their swift remediation upon detection. That detection may come from regularly scheduled assessments and the evaluation of anomalies that appear indicative of a serious condition. Section 7 of ASME/ANSI B31.8S provides that examination of these indications must occur "within a period not to exceed 5 days following determination of the condition," with "prompt[ ]" remediation thereafter of

any defect found to require repair or removal.[2] ASME/ANSI B31.8S, section 7 is incorporated in the HCA immediate repair criteria at § 192.933(d)(1) for operators to follow in their evaluation and remediation schedule. However, parallel language was inadvertently omitted from § 192.714(d). *See* 87 FR at 52246 (referencing ASME/ANSI B31.8S, section 7 in the preamble discussion supporting § 192.714).[3] This omission from § 192.714 leaves unintended asymmetry in the evaluation and remediation schedule for immediate repair conditions between HCA and non-HCA lines, with potential for operator confusion. As the § 192.714 repair criteria were intended to largely mirror those at § 192.933, PHMSA is correcting this oversight by adding to the beginning of § 192.714(d)(1) similar language that begins § 192.933(d)(1): ''An operator's evaluation and remediation schedule for immediate repair conditions must follow section 7 of ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7).''

Second, §§ 192.714(d)(3) and 192.933(d)(3) list various ''monitored conditions'' that entail less acute risk to public safety and the environment but which nevertheless merit monitoring by operators to ensure no further degradation occurs. Evidence supporting differentiation between a scheduled repair condition and a monitored repair condition can include an engineering critical assessment (ECA) demonstrating critical strain levels are not exceeded; conversely, exceedance of critical strain levels will often require a condition be scheduled for a repair under §§ 192.714(d)(2) and 192.933(d)(2). For that reason, PHMSA explained during the Gas Pipeline Advisory Committee (GPAC) meeting that it intended for dent repair criteria for both HCA and non-HCA areas to provide that ''[d]ents analyzed by ECA, but shown to not exceed critical strain levels[,] would be Monitored Conditions'' under §§ 192.714(d)(3) and 192.933(d)(3).[4] However, the regulatory text adopted by the August 2022 Final Rule included references to ECA as an element for only two of three monitored dent conditions in § 192.714 (applicable to non-HCA lines), even as it referenced ECA for all three monitored dent conditions in § 192.933 (applicable to HCA lines). *See* §§ 192.714(d)(3)(ii)–(iii) and 192.933(d)(3)(i)–(iii). The omission of ECA in the criteria at § 192.714(d)(3)(i) for dents on the bottom third (⅓) of the pipeline was inadvertent, as further demonstrated by reference to the same condition found in § 192.933(d)(3)(i) for HCA pipelines, which correctly includes the reference to an ECA. Accordingly, PHMSA is correcting the editorial oversight at § 192.714(d)(3)(i) by revising the regulatory language to provide that a dent on the bottom third (⅓) of a pipeline can be a monitored condition ''where an engineering analysis, performed in accordance with § 192.712(c), demonstrates critical strain levels are not exceeded.''

Third, PHMSA also clarifies that § 192.714(b) permits operators in certain circumstances to use the default values provided for in § 192.712(d)(3) and (e)(2) to calculate predicted failure pressure during repair operations when their documented material properties are unknown. Section 192.714(b) sets general, baseline requirements to ''ensure that the repairs are made in a safe manner'' and requires a ''pipeline segment's operating pressure [to] be less than the predicted failure pressure determined in accordance with § 192.712 during repair operations.'' Section 192.712 directs operators to use material property values that are documented in traceable, verifiable, and complete records where possible and provides conservative values operators may use where they are not. *See* § 192.712(d)(3), (e)(2). Operators must, in complying with §§ 192.714(b) and 192.933(a), either use documented material properties where they are available; obtain any missing documentation through § 192.607 where possible; or where such documentation is unavailable and cannot be obtained in a timely manner, employ the conservative assumptions in § 192.712 in their stead. *See* 87 FR at 52253. To make this clear, PHMSA is issuing a technical correction to add as the final sentence to both §§ 192.714(b) and 192.933(a): ''Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3).'' As PHMSA explained in the August 2022 Final Rule, an operator ''missing any material properties during anomaly evaluations and repairs'' should, through the ensuing repair operation, ''confirm those material properties under §§ 192.607 and 192.712(e) through (g)'' for future use. 87 FR at 52253.

B. Technical Correction to § 192.319(f) for Consistency With § 192.461(h) Regarding Schedule for Completing Any Necessary Repairs

PHMSA also intended in the August 2022 Final Rule to establish a consistent approach for scheduling remediation of severe coating damage for newly installed (pursuant to § 192.319) and existing (pursuant to § 192.461) pipelines to protect against corrosion. As PHMSA explained during the GPAC meeting, PHMSA intended both §§ 192.319 and 192.461 to provide operators 1 year total (contingent on obtaining any necessary permits) to complete the assessment of a pipe's corrosion protective coating and make any needed repairs; specifically, PHMSA intended to provide operators 6 months for the assessment plus 6 months from the assessment to complete any necessary repairs, with an allowance for permitting delays.[5] While § 192.461 contains language providing for this schedule at paragraphs (f) (assessment) and (h) (repair), and § 192.319 provides for the same schedule at paragraph (d) (assessment), PHMSA inadvertently omitted such language from paragraph (f) (repair) of § 192.319. PHMSA is therefore issuing a technical correction so that § 192.319(f) provides 6 months from the assessment, or as soon as practical after obtaining necessary permits, to complete any necessary repairs. This technical correction will also ensure that under § 192.319(f) operators apply for any needed permits within 6 months, mirroring the language in § 192.461(h).

C. Technical Correction To Specify the Unit Measurement in § 192.473(c)(3) Is in Alternating Current (AC)

Finally, among several provisions providing safety measures against potential corrosion, the August 2022 Final Rule includes language at § 192.473(c) obliging operators to conduct interference surveys to detect certain stray currents, for example, those from ''co-located pipelines, structures, or high voltage alternating current (HVAC) power lines.'' 87 FR at 52269 (amending § 192.473(c)(1)). Detecting and remediating interference surveys is essential to protecting pipeline integrity against stray currents

[2] Am. Soc'y Mech. Eng'rs, B31.8S–2004, ''Managing System Integrity of Gas Pipelines,'' sec. 7 (2005) (''ASME/ANSI B31.8S'').

[3] PHMSA included amendatory language at § 192.7(c)(6) to incorporate by reference ASME/ANSI B31.8S for § 192.714(d). *See* 87 FR at 52267.

[4] GPAC, Mar. 26 to 28, 2018 Meeting Slides at slide 150 (Mar. 2018); 87 FR at 52249. The GPAC meeting material is available on the public meeting page accessible at *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=132.*

[5] GPAC, June 6 to 7, 2017 Meeting Slides at slides 10 & 13 (June 2017) (providing 6 months for assessment ''plus 6 months to complete repairs''); GPAC, June 6, 2017 Meeting Transcript, at 40. The GPAC material is available on the public meeting page accessible at *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=123.*

that interfere with a corrosion control system. 87 FR at 52237. Section 192.473(c)(3), as adopted by the August 2022 Final Rule, requires that operators take remedial action when those surveys detect interference current that meets or exceeds 100 amps per meter square. The precise unit of measure is ''100 amps per meter squared alternating current (AC).'' 100 amps is calibrated as the appropriate value when measured in AC, as PHMSA has also specified in special permits it has issued, stating: ''Remedial action is required when the interference . . . is at a level that could cause significant corrosion (defined as 100 amps per meter square for AC-induced corrosion)[.]'' *See, e.g.,* Special Permit Requested by Natural Gas Pipeline Company of America, LLC, Class 1 to Class 3, Dkt. No. PHMSA–2019–0150 (Issued May 17, 2022), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-05/2019-0150-NGPL-Class-1-to-3-FL-SP-05-17-2022.pdf;* Special Permit Requested by Florida Gas Transmission Company, LCC, Class 1 to Class 3, Dkt. No. PHMSA–2020–0001 (Issued Mar. 31, 2022), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-04/2020-0001-Florida-Gas-Transmission-SP-Class-1-to-3-FL-SP-03-31-2022.pdf.* PHMSA is issuing a technical correction to clarify in the regulatory text of § 192.473(c)(3) that the unit of measure is in AC.

D. Response to Petitions for Reconsideration

PHMSA alerts the public and regulated community to its responses to petitions for reconsideration filed by the American Gas Association (AGA), the Interstate Natural Gas Association of America (INGAA), and the American Petroleum Institute (API). On September 23, 2022, AGA submitted a petition for reconsideration of the August 2022 Final Rule requesting clarification of two definitions at § 192.3 (regarding ''in-line inspection'' and ''transmission line'') and additional compliance time. *See* Docket No. PHMSA–2011–0023–0643. PHMSA's November 18, 2022, response letter to AGA's petition is available in the docket for this rulemaking at Docket No. PHMSA–2011–0023–0646.

Also on September 23, 2022, INGAA and API jointly submitted a petition for reconsideration of the August 2022 Final Rule that raised a wide variety of requests, including additional compliance time. *See* Docket No. PHMSA–2011–0023–0644. PHMSA's April 19, 2023, response letter to INGAA and API's petition is available in the docket for this rulemaking at Docket No. PHMSA–2011–0023–0649. Several of the issues raised in this petition have also informed technical corrections made in this notice.

IV. Regulatory Analyses and Notices

A. Legal Authority

Statutory authority for these technical corrections to the August 2022 Final Rule, as with that final rule itself, is provided by the Federal Pipeline Safety Act (49 U.S.C. 60101 *et seq.*). The Secretary delegated his authority under the Federal Pipeline Safety Act to the PHMSA Administrator under 49 CFR 1.97.

PHMSA finds it has good cause to make these five technical corrections without notice and comment pursuant to Section 553(b) of the Administrative Procedure Act (APA, 5 U.S.C. 551, *et seq.*). Section 553(b)(B) of the APA provides that, when an agency for good cause finds that notice and public procedure are impracticable, unnecessary, or contrary to the public interest, the agency may issue a rule without providing notice and an opportunity for public comment. These technical corrections, as explained above, are all editorial in nature and consistent with the intent of the recently published August 2022 Final Rule, which itself was the product of a decade-long rulemaking record with extensive notice and opportunity for comment, including various occasions for input through the GPAC at public meetings. The technical corrections make no substantive changes to the August 2022 Final Rule but merely facilitate its implementation by aligning the regulatory text with explanatory material in the August 2022 Final Rule's preamble and the administrative record. Because the August 2022 Final Rule is the product of an extensive administrative record with numerous opportunities (including through written comments and the advisory committee) for public comment, PHMSA finds that additional comment on the technical corrections herein is unnecessary.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

These technical corrections have been evaluated in accordance with existing policies and procedures and are considered not significant under Executive Order 12866 (''Regulatory Planning and Review'')[6] and DOT Order 2100.6A (''Rulemaking and Guidance Procedures''). While the August 2022 Final Rule received review by the Office of Management and Budget (OMB) under Executive Order 12866, these technical corrections (which are consistent with the final rule) are not considered significant and accordingly, this notice has not been reviewed under that authority. PHMSA finds that the technical corrections herein (in all respects consistent with the final rule) neither impose incremental compliance costs nor adversely affect safety.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act, as amended by the Small Business Regulatory Flexibility Fairness Act of 1996 (RFA, 5 U.S.C. 601 *et seq.*), generally requires Federal regulatory agencies to prepare a Final Regulatory Flexibility Analysis (FRFA) for a final rule subject to notice-and-comment rulemaking under the APA. 5 U.S.C. 604(a).[7] PHMSA did so for the August 2022 Final Rule, where the FRFA is available in the rulemaking docket, and that analysis remains unchanged as the technical corrections will impose no new incremental compliance costs.[8] Because PHMSA has ''good cause'' under the APA to forego comment on the technical corrections herein, no FRFA is required, consistent with the Small Business Administration's implementing guidance which explains that ''[i]f an NPRM is not required, the RFA does not apply.''[9]

D. Paperwork Reduction Act

The technical corrections in this notice impose no new or revised information collection requirements beyond those discussed in the August 2022 Final Rule.

E. Unfunded Mandates Reform Act of 1995

These technical corrections do not impose an unfunded mandate under the Unfunded Mandates Reform Act of 1995 (UMRA, 2 U.S.C. 1501 *et seq.*). PHMSA prepared an analysis of the UMRA considerations in the final regulatory impact analysis for the August 2022 Final Rule, which is available in the docket for the rulemaking.[10] These technical corrections have no substantial effect on that analysis as they will impose no new incremental compliance costs. PHMSA has analyzed the technical corrections in this notice

[6] 58 FR 51735 (Oct. 4, 1993).

[7] This requirement is subject to exceptions—which are not in any event applicable here because PHMSA has good cause to forego comment in adopting the technical correction herein.

[8] Final Regulatory Impact Analysis, Doc. No. PHMSA–2011–0023–0637, at 44 (Aug. 26, 2022).

[9] Small Business Administration, ''A Guide for Government Agencies: How to Comply with the Regulatory Flexibility Act'' 55 (2017).

[10] Doc. No. PHMSA–2011–0023–0637, at 44 (Aug. 26, 2022).

under the factors in the UMRA, as well, and determined that the technical corrections to the final rule herein do not impose enforceable duties on State, local, or Tribal governments or on the private sector of $100 million or more, adjusted for inflation, in any one year.

F. National Environmental Policy Act

The National Environmental Policy Act of 1969 (NEPA, 42 U.S.C. 4321 *et seq.*) requires Federal agencies to prepare a detailed statement on major Federal actions significantly affecting the quality of the human environment. PHMSA analyzed the August 2022 Final Rule in accordance with NEPA, implementing Council on Environmental Quality regulations (40 CFR parts 1500–1508), and DOT implementing policies (DOT Order 5610.1C, ''Procedures for Considering Environmental Impacts'') and determined the final rule would not significantly affect the quality of the human environment.[11] The technical corrections in this notice have no effect on PHMSA's earlier NEPA analysis prepared on the August 2022 Final Rule as the technical corrections are consistent, and merely facilitate compliance with, the August 2022 Final Rule. The purpose of the technical corrections is to further improve safety in conducting operations and repairs.

G. Privacy Act Statement

In accordance with 5 U.S.C. 553(c), DOT solicits comments from the public to inform its rulemaking process. DOT posts these comments, without edit, including any personal information the commenter provides, to *www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *www.dot.gov/privacy.*

H. Executive Order 13132 (Federalism)

PHMSA has analyzed this notice in accordance with the principles and criteria contained in Executive Order 13132 (''Federalism'').[12] PHMSA has previously determined that the August 2022 Final Rule itself did not impose any substantial direct effect on the States, the relationship between the National Government and the States, or the distribution of power and responsibilities among the various levels of government, *see* 87 FR at 52266; nor do the technical corrections herein, which are consistent with the August 2022 Final Rule and merely facilitate its compliance. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

I. Executive Order 13211

PHMSA analyzed the August 2022 Final Rule and determined that the requirements of Executive Order 13211 (''Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use'') [13] did not apply. Neither are these technical corrections to the rule a ''significant energy action'' under Executive Order 13211 as they are not likely to have a significant adverse effect on supply, distribution, or energy use. Further, OMB has not designated these corrections a significant energy action.

J. Executive Order 13175

This document was analyzed in accordance with the principles and criteria contained in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments'') [14] and DOT Order 5301.1 (''Department of Transportation Policies, Programs, and Procedures Affecting American Indians, Alaska Natives, and Tribes''). Because nothing herein has Tribal implications or imposes substantial direct compliance costs on Indian Tribal governments, the funding and consultation requirements of Executive Order 13175 do not apply.

K. Executive Order 13609 and International Trade Analysis

Under Executive Order 13609 (''Promoting International Regulatory Cooperation''),[15] agencies must consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements. The technical corrections to the final rule in this notice do not impact international trade.

L. Regulation Identifier Number (RIN)

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

List of Subjects in 49 CFR Part 192

Corrosion control, Incorporation by reference, Installation of pipe in a ditch, Integrity management, Internal inspection device, Management of change, Pipeline safety, Repair criteria, Surveillance.

In consideration of the foregoing, PHMSA further amends 49 CFR part 192, as amended August 24, 2022, at 87 FR 52224, and effective May 24, 2023, by making the following technical amendments:

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 1. The authority citation for part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et seq.,* and 49 CFR 1.97.

■ 2. Section 192.319, as amended August 24, 2022, at 87 FR 52269, and effective May 24, 2023, is further amended by revising paragraph (f) to read as follows:

§ 192.319 Installation of pipe in a ditch.

* * * * *

(f) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBμV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, *see* § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

* * * * *

■ 3. Section 192.473, as amended August 24, 2022, at 87 FR 52269, and effective May 24, 2023, is further amended by revising paragraph (c)(3) to read as follows:

§ 192.473 External corrosion control: Interference currents.

* * * * *

(c) * * *

(3) Development of a remedial action plan to correct any instances where

[11] Final Environmental Assessment, Doc. No. PHMSA–2011–0023–0635 (July 2022).

[12] 64 FR 43255 (Aug. 10, 1999).

[13] 66 FR 28355 (May 22, 2001).

[14] 65 FR 67249 (Nov. 6, 2000).

[15] 77 FR 26413 (May 4, 2012).

interference current is greater than or equal to 100 amps per meter squared alternating current (AC), or if it impedes the safe operation of a pipeline, or if it may cause a condition that would adversely impact the environment or the public; and

* * * * *

■ 4. Section 192.714, as added August 24, 2022, at 87 FR 52271, and effective May 24, 2023, is amended by revising paragraphs (b), (d)(1) introductory text, and (d)(3)(i) to read as follows:

§ 192.714 Transmission lines: Repair criteria for onshore transmission pipelines.

* * * * *

(b) *General.* Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made to prevent damage to persons, property, and the environment. A pipeline segment's operating pressure must be less than the predicted failure pressure determined in accordance with § 192.712 during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3).

* * * * *

(d) * * *

(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule for immediate repair conditions must follow section 7 of ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7). An operator must repair the following conditions immediately upon discovery:

* * * * *

(3) * * *

(i) A dent that is located between the 4 o'clock and 8 o'clock positions (bottom ⅓ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis, performed in accordance with § 192.712(c), demonstrates critical strain levels are not exceeded.

* * * * *

■ 5. Section 192.933, as amended August 24, 2022, at 87 FR at 52277, and effective May 24, 2023, is further amended by revising paragraph (a) introductory text to read as follows:

§ 192.933 What actions must be taken to address integrity issues?

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3).

* * * * *

Issued in Washington, DC, under authority delegated in 49 CFR 1.97.

Tristan H. Brown,

Deputy Administrator, Pipeline and Hazardous Materials Safety Administration.

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DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

[Docket No. FWS–R1–ES–2022–0062; FXES11130900000C6–234–FF09E42000]

RIN 1018–BG77

Endangered and Threatened Wildlife and Plants; Technical Corrections for 62 Wildlife and Plant Species on the Lists of Endangered and Threatened Wildlife and Plants

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Partial withdrawal of direct final rule.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), are withdrawing, in part, a February 2, 2023, direct final rule that revises the taxonomy of 62 wildlife and plant species listed under the Endangered Species Act of 1973, as amended (Act). For the Hawaiian hoary bat (*Lasiurus cinereus semotus*), we received comments relating to scientific research relevant to its taxonomic classification; and as a result, we are withdrawing the amendment in the direct final rule for this species only. The amendments in the direct final rule for the other 61 wildlife and plant species will be effective on May 3, 2023.

DATES: Effective April 24, 2023, the Service withdraws amendatory instruction 2.a published at 88 FR 7142 on February 2, 2023.

ADDRESSES: The direct final rule may be found online at *https://www.regulations.gov* under Docket No. FWS–R1–ES–2022–0062.

FOR FURTHER INFORMATION CONTACT: Marilet Zablan, Program Manager for Restoration and Endangered Species Classification, U.S. Fish and Wildlife Service, Pacific Regional Office, Ecological Services, 911 NE 11th Avenue, Portland, OR 97232; telephone 503–231–6131. Individuals in the United States who are deaf, deafblind, hard of hearing, or have a speech disability may dial 711 (TTY, TDD, or TeleBraille) to access telecommunications relay services. Individuals outside the United States should use the relay services offered within their country to make international calls to the point-of-contact in the United States.

SUPPLEMENTARY INFORMATION:

Background

Our regulations under the Endangered Species Act of 1973, as amended (Act; 16 U.S.C. 1531 *et seq.*), in title 50 of the Code of Federal Regulations at 50 CFR 17.11(c) and 17.12(b) direct us to use the most recently accepted scientific names for species on the Lists of Endangered and Threatened Wildlife and Plants (50 CFR 17.11(h) and 17.12(h)). Accordingly, on February 2, 2023, we published in the **Federal Register** a direct final rule (88 FR 7134) to revise the taxonomy and nomenclature of 62 wildlife and plant species listed under section 4 of the Act (16 U.S.C. 1531 *et seq.*). All of these changes are supported by peer-reviewed scientific studies and reflect taxonomy that has been accepted by taxonomic authorities. Specific references relevant to each species are cited in the text of the February 2, 2023, direct final rule, and the list of references is posted as a supporting document at *https://www.regulations.gov* under Docket No. FWS–R1–ES–2022–0062.

Consequently, we published the direct final rule without a prior proposal

CERTIFICATE OF SERVICE

I certify that on March 25, 2024, the foregoing was electronically filed through this Court's CM/ECF system, which will send a notice of filing to all registered users.

/s/ Catherine E. Stetson
Catherine E. Stetson